B O N N E V I L L E   P O W E R   A D M I N I S T R A T I O N

2007 Supplemental Wholesale Power Rate Case Initial Proposal

REBUTTAL TESTIMONY

Volume 2

May 2008

BPA Exhibit No.	Witness
WP-07-E-BPA-83	Boling, Manary, McClain, McHugh, Shaughnessy, Young
WP-07-E-BPA-84	Lee, Homenick, Johnson
WP-07-E-BPA-85	Doubleday, Bliven, Brodie, Homenick, Mace
WP-07-E-BPA-86	Normandeau, Conger, Lovell, Marks, Russell, Wagner

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Section 1: Introduction and Purpose of Testimony

Q. Please state your names and qualifications.

A. My name is Rod Boling and my qualifications are contained in WP-07-Q-BPA-06.

A. My name is Michelle Manary and my qualifications are contained in WP-07-Q-BPA-63.

A. My name is Paul W. T. McClain and my qualifications are contained in WP-07-Q-BPA-37.

A. My name is W. Michael McHugh and my qualifications are contained in WP-07-Q-BPA-65.

A. My name is Julia Shaughnessy and my qualifications are contained in WP-07-Q-BPA-67.

A. My name is Robert E. Young and my qualifications are contained in WP-07-Q-BPA-69.

Q. Have you previously submitted testimony in this Supplemental Proceeding?

A. Yes. Ms. Manary, Mr. Boling, Mr. McClain, and Ms. Shaughnessy submitted direct testimony identified as Exhibit WP-07-E-BPA-61. Mr. Young submitted direct testimony, together with other witnesses, identified as Exhibit WP-07-E-BPA-71. Mr. Boling and Mr. McClain submitted direct testimony, together with another witness, identified as Exhibit WP-07-E-BPA-57. Mr. Boling submitted direct testimony, together with other witnesses, identified as Exhibit WP-07-E-BPA-62.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to respond to direct testimony submitted by various parties concerning assumptions and calculations in the average system cost (ASC) forecasts and backcasts. We respond to the direct testimony of Cowlitz County PUD and Clark Public Utilities (Cowlitz/Clark), WP-07-E-JP17-01; the Western Public Agencies Group (WPAG), WP-07-E-WA-05; the Association of Public Agency Customers (APAC), WP-07-E-AP-1; and the Pacific Northwest Investor-Owned Utilities (IOUs), WP-07-E-JP6-08.

Q. How is your testimony organized?

A. Our testimony is divided into four main sections. Section 1 is this introduction. Section 2 is our response to arguments and evidence challenging BPA's revised ASC forecasts. Section 3 is our response to arguments and evidence challenging BPA's backcast ASCs. Section 4 addresses challenges to BPA's compliance with the 1984 Average System Cost Methodology (1984 ASCM) when constructing both the revised forecast ASCs and the backcast ASCs.

Section 2: ASC Forecasts

Section 2.1: WP-02 Revised ASC Forecasts

Section 2.1.1: General Accuracy of WP-02 Revised ASC Forecasts

Q. Cowlitz/Clark contend that although they have not done a detailed examination of BPA's ASC derivations, they claim that a "cursory review" of the ASCs shows that BPA's ASCs are too high in FY 2002 for several of the utilities. Schoenbeck and Beck, WP-07-E-JP17-01 at 32. As an example, Cowlitz/Clark note BPA's forecast of PacifiCorp's Idaho jurisdiction, which was $82.61 per megawatthour for FY 2002. Id. Cowlitz/Clark then compares this forecast to a number of benchmarks. Id. Before addressing these benchmarks, do you agree that a cursory review of the ASCs shows that BPA's ASCs are generally too high?

A. No. The direction we were given in this proceeding was to evaluate whether the ASC *forecasts* would need to be updated assuming that BPA could use information available in the winter of 2000 and spring of 2001 timeframes noted in the policy testimony. *See* Burns, *et al.,* WP-07-E-BPA-53 at 8. We then reviewed the information we had at the time and the information available in the record to determine what would have been updated. With this context in mind, there are two salient points that explain why these ASC forecasts would not likely have been viewed at the time as being inappropriately high, and therefore, in our opinion, would not need to be readjusted.

First, these ASCs were being developed from previous ASC filings made by the IOUs in the mid-to-late 1990s. This is in line with BPA's historical approach to forecasting ASCs. Because these ASCs were from earlier years, BPA had to use a forecasting model to calculate forecast ASCs that would cover the FY 2002-2006 rate period. The forecasting model developed to perform this function used standard features to escalate ASCs. When BPA presented this method of forecasting ASCs and the model in the original WP-02 rate case, BPA received no comments or objections from any party in the case. The model's algorithm used purchase power to meet forecast load growth, an assumption common in such models. Because the model appeared to be working correctly, and no party raised any objections to it, we think it would have been highly unlikely that BPA would have reconsidered the model's output unless it produced a result that was patently unreasonable.

Cowlitz/Clark seem to contend that a high ASC for a single utility for one year would have prompted BPA to abandon the forecast model. We disagree. At the time we would have revisited these ASCs (*i.e.*, winter/spring 2001) we would likely have determined that a high ASC forecast for FY 2002 was a reasonable deviation from the normal ASC projections because of the astoundingly high market price forecast of $148 per megawatthour. We, at the time, had no basis to assume that this high market price would abate in the coming fiscal year. There would, therefore, not have been an obvious need to adjust the model's algorithm or, in the alternative, rely on benchmark data to establish a lower ASC as Cowlitz/Clark recommend. *Id.*

Second, even if this single year deviation could be considered unreasonably high, which we do not think it would, it is also reasonable to assume that BPA would have concluded that the overall effect of this one year was small. We would have noted that this one ASC counted for only one year of a five-year rate period. The remaining four years of ASC data appeared to be at reasonable levels. In addition, we would have noted that this one ASC affected only PacifiCorp's Idaho Division exchange load for 2002, which overall equated to less than three percent of total IOU exchange load. *See* Wholesale Power Rate Development Study Documentation, WP-02-FS-BPA-05A at 146-147. Based on these factors, we think BPA ultimately would have concluded that the ASC forecasting model's output remained reasonable, and would not have looked to other potential benchmarks or data to estimate ASCs for the WP-02 rate period.

Section 2.1.2: WP-02 Revised ASC Forecasts Compared to Benchmarks

Q. Did any party present specific examples to support their claim that BPA's revised WP-02 ASC forecasts were too high?

A. Yes. Cowlitz/Clark compared BPA's revised WP-02 ASC forecasts with several benchmarks that, in their view, show BPA's forecast ASCs were high. *Schoenbeck and Beck, WP-07-E-JP17-01 at 32-34.*

Q. What benchmarks do Cowlitz/Clark recommend that BPA should have used to test its forecast ASCs?

A. The first is the average residential rates of the IOUs. Schoenbeck and Beck, WP-07-E-JP17-01 at 32-33. They argue that these rates include distribution costs in the range of 35-45 percent prior to the energy crisis and, more recently, 30 percent of the overall residential rate. *Id.* Cowlitz/Clark claim that during 2002, the average rate paid by PacifiCorp's 45,000 residential customers in Idaho was only $76 per megawatthour. *Id.* Cowlitz/Clark say that this test alone suggests the BPA-derived ASC is far too high since it is greater than the entire average rate paid by residential customers. *Id.* If it were assumed that just 30 percent of this charge is related to distribution costs, Cowlitz/Clark conclude that the maximum ASC value would be around $53 per megawatthour (before income tax, return on equity and revenue tax exclusions). *Id.*

Q. Do you agree with this comparison?

A. We do not disagree that benchmarks can be one of many tools that could have been used to evaluate – even forecast – ASCs. However, as discussed in our answer above, the forecast results for FY 2002 generally, and PacifiCorp's Idaho Division specifically, would not have warranted a complete revision of the forecasting model.

Q. What other benchmark do Cowlitz/Clark note?

A. Cowlitz/Clark also argue that the rates charged to large industrial customers provide a second readily available yardstick to measure the reasonableness of BPA's ASC projections. Schoenbeck and Beck, WP-07-E-JP17-01 at 33. Cowlitz/Clark claim that these rates are typically dominated by power supply—and therefore "exchangeable"—costs. *Id.* For customers served from the transmission system, the power supply portion (production and transmission costs) will be about 90 percent of the overall retail industrial rate level. *Id.* During 2002, the over 100 large power customers PacifiCorp serves in Idaho paid an average rate of just $47 per megawatthour. *Id.* Cowlitz/Clark conclude that this indicates a properly projected ASC founded upon Commission-approved charges would be below $47 per megawatthour. *Id.*

Q. Is this an accurate comparison?

A. Again, possibly, but such a comparison is not dispositive. As explained above, such a comparison would not reasonably have led us to either abandon or even revise the ASC forecasting model.

Q. What other benchmarks do Cowlitz/Clark suggest?

A. Cowlitz/Clark say that BPA should have used the semi-annual, annual or bi-annual reporting that some state regulatory commissions require as the foundation for BPA's ASC forecasts for FY 2002-2006. Schoenbeck and Beck, WP-07-E-JP17-01 at 33-34.

Q. Do you agree?

A. No.

Q. Why didn't you use reports filed with regulatory commissions?

A. We did not use such reports for two simple reasons: first, as described above, we had no reasonable basis for revising or abandoning the ASC forecast model, so using such reports would have been viewed as unnecessary; and, second, we do not believe BPA could have reasonably collected and evaluated such reports during the winter/spring 2001 time period.

Q. Cowlitz/Clark note that PGE made some rate filings during 2000. Schoenbeck and Beck, WP-07-E-JP17-01 at 33-34. Please summarize their argument.

A. Cowlitz/Clark point to unbundling application filings made by PGE during 2000. *Id.* According to Cowlitz/Clark, PGE filed an unbundling application, and from this document PGE's ASC can be "no greater than" $40 per megawatthour for CY 2002. *Id.* The Oregon Commission issued a ruling in June of 2001, noting that PGE's "power costs" had increased 173 percent to an average of $37.4 per megawatthour, but BPA's backcast shows $54.54 per megawatthour. *Id.* Replacing the $54.54 per megawatthour with the $37.4 per megawatthour means PGE's lower ASC eliminates PGE's ASC benefits of $94.4 million. *Id.*

Q. Please respond.

A. We have some criticisms of the analytical work that Cowlitz/Clark did to calculate PGE's power costs. We will, however, not address these issues here because it appears that

Cowlitz/Clark is challenging our backcast ASCs in this paragraph. We will therefore address these analytical deficiencies in Section 3 of this testimony.

Q. *Cowlitz/Clark also argue that PacifiCorp made several filings with the Oregon and Idaho commissions in the 2000-2001 timeframe. Schoenbeck and Beck, WP-07-E-JP17-01 at 34. For example, PacifiCorp made an "unbundling" filing and a filing to defer excess power costs in November 2000. Id. PacifiCorp also submitted a power cost deferral filing in Idaho. Id. Cowlitz/Clark contend that these applications would have been an "excellent starting point – if not the only starting point – for deriving utility ASC forecasts consistent with the 1984 ASCM." Id. Do you agree?*

A. No. First, as discussed fully in Section 4.1, the 1984 ASCM does not define how BPA will forecast ASCs in power rate cases. Further, collecting, evaluating, and incorporating the information contained in these PacifiCorp filings could not have been completed in the winter/spring 2001 period. Furthermore, with the ASC forecast model not having been challenged, the decision not to pursue such an approach would, we believe, have been quite an easy one to make.

Section 2.1.3: WP-02 ASC Forecasts – Preference Customers

Q. *Did the parties raise any other objections to the ASC forecasts BPA used for the COUs for the 2002-2006 period?*

A. Yes. WPAG questions why we did not update the ASC forecasts of the COUs in the reforecast for FY 2002-2006. Grinberg, *et al.*, WP-07-E-WA-05 at 39. WPAG calls this omission an "inconsistent approach" to determining whether the COUs would exchange with BPA in the FY 2002-2006 period. *Id.*

Q. *Do you agree?*

A. No. As we stated in our testimony (Boling, *et al.*, WP-07-E-BPA-57), we would have assumed in June 2001 that the retail loads of Snohomish PUD and the City of Idaho Falls would have been served by BPA at the lower than market PF rate, with an effect on ASC that would not lead to REP benefits. Unstated in our testimony, but a practical consideration nonetheless, is that BPA had very little current financial and operating data on Snohomish with which to revise its ASCs. BPA had a bit more current information on Idaho Falls and Clark Public Utilities (CPU).

Q. WPAG argues that had BPA applied the same data revision approach to preference customers that it used in forecasting IOU ASCs, and if CPU had been faced with much lower PF-02 and PF-07 PF Exchange rates as derived in the Supplemental Proposal, CPU would have been forecast to qualify for substantial REP benefits. Grinberg, et al., WP-07-E-WA-05 at 40-41. As such, WPAG argues that BPA should assume that CPU would have entered the Residential Exchange Program for the FY 2002-2006 period. Id. Do you agree?

A. No, we do not agree. We do not think that we must assume that CPU would be in the REP for purposes of this proceeding.

BPA knew with virtual certainty that, in the absence of the REP Settlement Agreements, the IOUs were going to participate in the REP during the WP-02 rate period. This assumption is based on the fact that the IOUs had submitted letters requesting to participate in the REP. BPA, in turn, offered the IOUs both Residential Purchase and Sale Agreements (RPSA) and REP Settlement Agreements. Instead of signing RPSAs, though, the IOUs signed REP Settlement Agreements. This series of events created a strong evidentiary foundation supporting BPA's assumption that, but for the REP Settlement Agreements, the IOUs would have participated in the REP.

No such foundation, however, exists for CPU. CPU did not submit a letter notifying BPA of its intent to participate in the REP in FY 2002, nor did it request BPA to provide it with an RPSA. Thus, we are unaware of any direct evidence that would support WPAG's assertion that CPU would have been in the program as was the case for the IOUs. BPA has also been unable to substantiate, even through circumstantial facts, CPU's intent to participate in the REP. In discovery, BPA asked for data from WPAG to substantiate that CPU was intending to enter the program. None of the answers to discovery requests supports such a conclusion. For example, CPU had hedged gas prices through 2004, three years of BPA's five-year rate period, at levels considerably lower than the generally accepted market price forecasts of the time. *See* responses to Data Request Nos. BPA-WA-21 and 22 (Attachments 1 and 2). In addition, BPA was unable to obtain any data or analyses relied upon by CPU to estimate future gas prices. *See* response to Data Request No. BPA-WA-36 (Attachment 3). Nor had CPU apparently even taken the preliminary step of estimating its ASC any time within two years prior to winter/spring 2001. *See* response to Data Request No. BPA-WA-23 (Attachment 4). Taken together, the foregoing responses demonstrate CPU's general intent to not participate in the REP during the period prior to winter/spring 2001, which supports our original position not to assume for reforecast purposes that CPU would have been in the REP.

Q. *WPAG argues that if BPA updated CPU's ASC in the same manner as BPA did for the IOUs, then CPU would have been eligible for substantial REP benefits. Grinberg, et al., WP-07-E-WA-05 at 40. Is this correct?*

A. No. Even assuming CPU had expressed an interest in the REP, we could not update CPU's ASC in the same way we updated the IOU ASCs because the WP-02 record does not have the model necessary to do the update. However, to test WPAG's assertion, we escalated CPU's ASC by 30 percent based on WPAG's comment that BPA's IOU reforecasts increased ASCs about 30 percent. *Id.* at 35-36. The result would increase BPA's original WP-02 forecast of CPU's ASC of $27.57 per megawatthour, which was unchallenged, to an ASC of $35.84 per megawatthour. Wholesale Power Rate Development Study Documentation, WP-02-FS-BPA-05A at 112. In the instant proceeding, we recalculated what the PF Exchange rate would likely have been if the REP Settlement Agreements had not been in effect. The revised PF Exchange rate for 2002 in the Supplemental Proposal is $39.95 per megawatthour. Lookback Study, WP-07-E-BPA-44A at 138. As can be seen, CPU's forecast ASC would still have been lower than the revised PF Exchange rate by $4.09 per megawatthour, so BPA's assumption to leave CPU out of REP consideration would continue to be correct.

Q. WPAG also argues that BPA should assume that with the lower PF-02 and PF-07 Exchange rates as postulated by BPA, CPU would not sign an REP Settlement Agreement that would provide materially smaller benefits than would participation in the REP. Grinberg, et al., WP-07-E-WA-05 at 41. Do you agree?

A. No. BPA does not think it reasonable to assume that CPU would not have entered into the REP Settlement Agreement for purposes of the Lookback analysis. First, CPU's REP Settlement Agreement was not challenged in Court by any party. CPU's REP Settlement Agreement, therefore, is not in the same situation as BPA's other REP settlement agreements with the IOUs, which were found unlawful by the Court. We note that CPU's REP Settlement Agreement has been operating since the Court's May 2007 decisions and remains in effect. As a general matter, then, BPA does not think it reasonable to assume away an agreement that is in full force and effect even today.

Second, it is our understanding that this particular REP Settlement Agreement included certain other matters that were not present in BPA's other REP settlement agreements. That is, there were other rights and obligations satisfied through CPU's agreement. If BPA were to assume CPU would not have signed an REP Settlement Agreement, BPA would also have to assume that CPU would not have wanted the other terms and conditions of the REP Settlement Agreement. BPA, however, cannot determine with any degree of certainty what CPU's complete motivations were for entering into the REP Settlement Agreement. Any attempt by BPA to make such an assumption would be based on speculation and guesswork. The better and more reasonable assumption is to assume in the Lookback analysis what actually happened: CPU signed an REP settlement agreement that remains in effect today.

Q. WPAG provided an estimate of CPU's ASC they claim is comparable to the IOUs' ASCs for the 2002-2006 period. Grinberg, et al., WP-07-E-WA-05 at 40-41. They argue BPA should use these estimates in its ASC forecast. Id. Do you agree?

A. No. First, WPAG's ASC determination is not comparable to our forecasts for the IOUs. WPAG started with an actual filing in September 2005 (which did not undergo a formal review process and was never approved by BPA) and then worked backward using actual natural gas prices and certain known escalation rates. WPAG's ASC analysis is thus akin to a backcast ASC. In the winter/spring of 2001, BPA did not have the information WPAG is now claiming we should assume it had. Regardless, we had an ASC estimate for CPU in the record that we had developed in cooperation with CPU that we considered to be sufficient for the rate case. *See* Boling and Doubleday, WP-02-E-BPA-30 at 9.

Section 2.2: FY 2007-2008 Revised ASC Forecasts

Section 2.2.1: General Accuracy of FY 2007-2008 Revised ASC Forecasts

Q. Did any party raise any specific issues with BPA's proposed ASC forecasts for FY 2007-2008?

A. Yes. WPAG raised a number of concerns with BPA's FY 2007-2008 ASC forecasts.

Q. What specific objections did WPAG present?

A. WPAG took particular issue with BPA's use of the FERC Form 1 as the source of data for the FY 2007-2008 ASCs. Grinberg, *et al.*, WP-07-E-WA-05 at 36-37. WPAG argues that the FERC Form 1 data are not the same sort of data that would be used by a utility to set rates. *Id.* WPAG claims that, in the rate setting process, a utility would define a test period of one or more years, would then use costs and loads that have been normalized for the specific test period, and the costs would then be subject to scrutiny by the state commission and other parties. *Id.* In WPAG's view, the FERC Form 1 data are simply a reporting of actual data by the utility. *Id.* They claim there is no tie-in to the ratemaking process, and there is no analysis or examination of the data for year-to-year changes or differences. *Id.* Because the FERC Form 1 data have not been subject to review or adjudication in a rate setting process before a regulatory or utility governing body, there is a higher likelihood of data entry errors and other anomalies. *Id.*

Q. What is your response to this argument?

A. Because the FERC Form 1 is the source of data for both the forecast ASCs for FY 2007-2008 and the backcast ASCs for FY 2002-2008, we will respond to WPAG's specific concerns about the quality of the FERC Form 1 data in the backcast ASC section of this testimony (Section 3). As explained in that section, BPA considers the data available in the FERC Form 1 equal to if not superior to the data that can be found in the hodgepodge of state jurisdictional rate orders for the six IOUs.

Q. WPAG states that BPA's use of the FERC Form 1 had an "impact" on the ASC forecasts performed by BPA, but they cannot tell whether it is an upward or downward bias. Grinberg, et al., WP-07-E-WA-05 at 37. WPAG is confident, though, that the end results would have been different had BPA used the jurisdictional rate orders. Id. Please respond to this comment.

A. We will respond to this particular statement below after we have discussed the benchmark WPAG relied upon to make this statement. However, as a general matter, there is no evidence that any such differences would have been dramatic. As explained more fully in Section 3, the ASCs we calculated with the FERC Form 1 were, in most respects, either very close to or lower than the many benchmarks proffered by WPAG and the other parties. Consequently, the "impact" of using the FERC Form 1 as the data source for the IOUs' forecast ASCs is, by and large, quite small. We believe that this minor impact is reasonable when compared to the massive administrative burden that BPA and the rate case parties would have been under had we reviewed and compiled every state jurisdictional filing that resulted in a rate change for six IOUs, operating in four states, assuming we could even have conducted such a review.

Section 2.2.2: FY 2007-2008 Revised ASC Forecasts Compared to Benchmarks

Q. Did any party compare BPA's ASC forecasts to a benchmark, like Cowlitz/Clark?

A. Yes. WPAG presented some evidence comparing BPA's FY 2007-2008 forecast ASCs to a benchmark.

Q. What benchmark did WPAG use?

A. WPAG performed an analysis of Avista's ASC by comparing an ASC determined by BPA using data from a retail rate order with the ASC we calculated using data from the FERC Form 1 from the same period. Grinberg, *et al.*, WP-07-E-WA-05 at 37-38. According to WPAG, this comparison demonstrated that the ASC calculated using FERC Form 1 data was about 2.3 percent higher than that calculated using the retail rate filing of the same vintage. *Id*. In an erratum correction, WPAG states that the ASC calculated using FERC Form 1 data was about **1.6 percent** higher. WPAG claims that this result is likely representative of other IOU ASC forecasts performed by BPA for the recalculations of the 7(b)(2) rate ceiling. *Id*.

Q. Did you request information regarding the calculation of the 2.3 (1.6) percent differential?

A. Yes. BPA submitted Data Request No. BPA-WA-11, which requested that WPAG provide all the information that was used to develop the ASC and the differential.

Q. What response did you receive?

A. WPAG's response stated that the Avista filing discussed above occurred in 1983. *See* response to Data Request No. BPA-WA-11*,* Attachment 5.

Q Do you think the vintage of this filing is relevant to the reforecast 2007 and 2008 ASCs that you calculate?

A. No. The 1983 filing before the WUTC predates approximately twenty years of changes in the electric utility industry. This filing was made when the 1984 ASCM was being developed and at a time when terminated plants were being adjudicated by regional regulatory commissions as well as being addressed in ASC filings.

Q. Do you have other concerns regarding WPAG's evaluation of Avista's ASC?

A. Yes. We think there is an inconsistency in WPAG stating that the 1984 ASCM requires an ASC for each utility be computed using information from the most recent retail rate filing by the utility, and yet their analysis relies on a filing from 1983. But even if we ignore this inconsistency, their analysis is based on data that do not reflect changes in the electric utility industry that have transpired in the last twenty years.

Q. As noted above, WPAG previously stated that BPA's use of the FERC Form 1 had an "impact" on the ASC forecasts performed by BPA, but they cannot tell whether it is an upward or downward bias. Grinberg, et al., WP-07-E-WA-05 at 37. WPAG is confident, though, that the end results would have been different had BPA used the jurisdictional rate orders. Id. Having now reviewed the basis for this statement, please respond to this statement.

A. WPAG's analysis is far too inconclusive for WPAG to conclude it is reasonable to assume that there is any kind of bias in our ASC results. However, if, for example, there should happen to be a consistent upward bias of 1.6 percent, the increase to our forecast ASCs would have been less than $1.00 per megawatthour, showing the differences would not have been dramatic.

Section 2.3: Exchangeable Load Forecast

Q. What other issues did parties claim were faulty with your ASC forecasts?

A. APAC says that BPA did not have filings of exchange loads from the IOUs pursuant to the 1984 ASCM, which also are essential to calculating the impacts of the Residential Exchange. Wolverton, WP-07-E-AP-1 at 33.

Q. Do you agree?

A. No. The 1984 ASCM does not specify what method BPA must use to forecast either IOU system loads or exchange loads for rate case purposes. However, BPA requested and received contract system load and exchange load forecasts for 2002 through 2010 from the IOUs during 1998-1999. BPA therefore had very recent load forecasts from the IOUs upon which it could forecast ASCs for the WP-02 rate period.

For the WP-07 rate period, we used the most recent IOU load forecasts that were submitted to the PNUCC and published in BPA's "White Book." These data were the best available when we were forecasting ASCs for the WP-07 period.

Section 3: ASC Backcasts

Section 3.1: ASC Backcasts FY 2002-2008

Section 3.1.1: General Accuracy of Backcast ASCs

Q. Did any party file direct testimony challenging the general accuracy of the backcast ASCs?

A. Yes. Cowlitz/Clark, WPAG, and APAC filed direct testimony challenging our backcast ASC calculations and assumptions. Cowlitz/Clark argues that we have overstated the backcast ASCs. Schoenbeck and Beck, WP-07-E-JP17-01 at 35. WPAG is a little less emphatic, and says that there is a "likelihood" that our backcast ASCs are higher than they would have been had we relied on jurisdictional retail rate filings as required by the 1984 ASCM. Grinberg, *et al.*, WP-07-E-WA-05 at 43. APAC's arguments were even less sure. They noted that there is no way of knowing how our backcasts would differ from actual ASC filings because it would be virtually "impossible" to revisit all the rate setting decisions that each jurisdiction made. Wolverton, WP-07-E-AP-1 at 45.

Q. *Did you perform any analysis to test these assertions that the backcast ASCs were likely higher than jurisdictional ASCs?*

A. Yes. To test the parties' claims, we looked at an ASC filing that had gone through the jurisdictional process and then compared it to an ASC we calculated from relevant FERC Form 1 data for the same utility. Our test case was Puget Sound Energy's last jurisdictional ASC filing with BPA (BPA Docket No. 7-A2-9501), which used a test period of October 1, 1995, through September 30, 1996. We compared this jurisdictional ASC with an ASC we determined using PSE's 1996 FERC Form 1 data. The final ASC determination in BPA Docket No. 7-A2-9501 was $36.53 per megawatthour and the ASC we calculated using the 1996 FERC Form 1 data for PSE resulted in an ASC of $35.79 per megawatthour. In other words, the ASC we calculated using the FERC Form 1 data was $0.67 per megawatthour *lower* than the ASC determined using the jurisdictional approach. Attachment 6 is a detailed line by line comparison of the ASC determined in BPA Docket No. 7-A2-9501 and the ASC calculated using the 1996 FERC Form 1. We recognize that there may be differences between data sources that caused this differential. However, we think this analysis shows that WPAG's assertion that there is a good "likelihood" that BPA's backcast ASCs are higher than they would have been had we relied on jurisdictional retail rate filings is unfounded.

Q. *Did you do a similar review for any other utility?*

A. Yes. We also reviewed PacifiCorp's 1997 Oregon jurisdiction ASC filing, BPA Docket No. 5-A1-9601. PacifiCorp used a July 1, 1996, to June 30, 1997, test period. We compared this jurisdictional ASC with an ASC we determined using PacifiCorp's 1997 FERC Form 1 data.

Q. How did you allocate the total PacifiCorp costs to Oregon?

A. We used the ASC Cookbook for PacifiCorp that uses 2002 PacifiCorp allocation factors that were developed in cooperation with and approved by PacifiCorp's various regulatory commissions, which we assumed would be a reasonable proxy for the 1997 data.

Q. What were the results of this review?

A. PacifiCorp's jurisdictional-based ASC Final Report (5-A1-9601) determined a final ASC of $27.00 per megawatthour. Using PacifiCorp's 1997 FERC Form 1 as the source of data resulted in a final ASC of $26.95 per megawatthour, which is $0.05 less than BPA's ASC determination. Attachment 7 is a detailed line by line comparison of the ASC determined in BPA Docket No. 5-A1-9601 and the ASC calculated using the 1996 FERC Form 1.

Q. What is your conclusion regarding these ASC comparisons for Puget and PacifiCorp?

A. These reviews indicate that using FERC Form 1 data as the source to calculate the utilities' ASCs results in ASC determinations that are very close to the ASCs determined from a jurisdictional filing. In the two cases we evaluated, the resulting ASCs were either less than the jurisdiction-based ASC or substantially the same. We have no reason to doubt that closeness of ASC results between using FERC Form 1 data and jurisdictional-filed ASCs would continue through the 2002-2008 Lookback period.

Q. APAC noted that there is no way of knowing how BPA's backcasts would differ from actual ASC filings because it would be virtually "impossible" to revisit all the rate setting decisions that each jurisdiction made. Wolverton, WP-07-E-AP-1 at 45. Please respond.

A. We concur it is likely administratively impossible to apply the 1984 ASCM to all rate changes granted to PNW IOUs over the last seven-plus years to calculate the ASCs now for this proceeding. This is why BPA has chosen to address the backcast ASCs using FERC Form 1 data.

Section 3.1.2: Backcast ASCs Compared to PSE and PGE Benchmarks

Q. *Did any party present specific examples to support their claim that BPA's backcast ASCs were too high?*

A. Yes. Cowlitz/Clark argue that BPA has overstated its backcast ASCs. Schoenbeck and Beck, WP-07-E-JP17-01 at 35. They reach this conclusion by focusing their analysis on Puget Sound Energy, which they claim made at least one filing before the state utility commission each year of the Lookback period. *Id.* Since July 2002, PSE has had a purchase cost adjustment mechanism in place and the ability to file what is referred to as a "power cost only rate case." *Id.* Cowlitz/Clark assert that PSE has a known Commission approved "base power cost" from which BPA could have determined an accurate ASC in compliance with the 1984 ASCM for the entire Lookback period. *Id.* They also state that PSE's power cost rates have changed seven times from July 2002 through September 2007. *Id.* They conclude that, in PSE's case, it is inappropriate to rely on FERC Form 1 information as BPA did for all exchanging utilities in deriving backcast ASCs. *Id.*

Q. *Do you agree with Cowlitz/Clark's assessment?*

A. No. Cowlitz/Clark is referring to PSE's power cost adjustment mechanism. This mechanism accounts only for PSE's "base power cost," which is only a portion of PSE's total exchangeable costs that would be included in an ASC determination under the terms of the 1984 ASCM. For example, the "base power cost" may not include increases in non-power cost accounts or rate base changes over time. Cowlitz/Clark's proposal therefore would not be an appropriate method to calculate backcast ASCs.

Q. *When BPA implemented the REP, did BPA review power cost adjustment filings?*

A. Yes. BPA reviewed power cost adjustment filings and similar types of filings during implementation of the REP. BPA's reviews of such filings resulted in adjustments to ASCs. For example, when PGE's Trojan nuclear power plant was being terminated, PGE made "Power Replacement" filings. In those cases, PGE used its last approved ASC filing that included a review of all costs and rates of return allowed in rates, and then adjusted such total costs for the new power replacement costs. In this manner the ASC was re-determined but still included <u>all</u> exchangeable costs.

Q. Did you review the data that Cowlitz/Clark relied upon to calculate PSE's ASC?

A. Yes. Cowlitz/Clark's response to Data Request No. BPA-JP17-3 (Attachment 8) notes that the "PCA ASCs" are simply the base power costs approved by the Washington Utilities and Transportation Commission (WUTC) in the seven dockets changing PSE's rates from 2002 through 2007. We reviewed the Excel file attached to the data response and were able to track the power cost values, except for 2005, which underestimated the power costs. The "PCA ASC" that we calculated was $49.29 per megawatthour compared with the $47.85 per megawatthour that Cowlitz/Clark calculated. Using the correct version reduces the differential between the PCA ASC and backcast ASC from $(2.83) per megawatthour to $(1.43) per megawatthour.

Q. Do you have other comments regarding Cowlitz/Clark's response?

A. Yes. Cowlitz/Clark provided PCA data for 2007, but did not use it in Cowlitz/Clark's model to show a comparison to the 2007 ASC backcast. Using the model Cowlitz/Clark provided, we determined the 2007 "PCA ASC" would be $57.88 per megawatthour. We included the exchange loads that were calculated for the 2007 backcast ASC.

Q. How does this compare with the 2007 backcast ASC for PSE?

A. The 2007 backcast ASC for PSE is $53.66 per megawatthour. Lookback Study Documentation, WP-07-E-BPA-44A at 1013. The differential shows that BPA's calculation would be $4.22 lower than the "PCA ASC." If we use Cowlitz/Clark's model, 2007 PSE benefits would be $49.6 million greater than the backcast ASC produced.

Q. Did Cowlitz/Clark point to any other benchmarks to support its assertion that your backcast ASCs were overstated?

A. Yes. Cowlitz/Clark note PGE made application filings during 2000 in response to "unbundling." Schoenbeck and Beck, WP-07-E-JP17-01 at 34. According to Cowlitz/Clark, PGE filed an unbundling application, and from this document PGE's ASC can be "no greater than" $40 per megawatthour for CY 2002. *Id.* The Oregon commission issued Order No. 01-777 in the UI 115 proceeding in August 2001, noting that PGE's "power costs" had increased 173 percent since 1997 to an average of $37.4 per megawatthour. *Id.* BPA's backcast ASC, however, is $52.54 per megawatthour for FY 2002. Lookback Study Documentation, WP-07-E-BPA-44A at 1013.

Q. Is this a proper comparison?

A. No. The filing Cowlitz/Clark refers to is the unbundling application that started in October 2000. The $37.4/MWh refers only to the power cost portion of PGE's total costs. The $37.4/MWh value probably includes such items as the variable net generation and fuel related power costs of PGE, including purchases, and the credit for sales for resale revenues. It does not include non-power costs such as return on rate base, depreciation and other costs that are typically not part of a PCA filing but are included in an a utility ASC filing and are included in our Lookback ASC estimates. So, comparing BPA's backcast ASC of $52.54/MWh with PGE's power cost of $34.70 MWh is an apples and oranges comparison.

Q. Can you remove costs from the $52.54/MWh backcast ASC estimate for PGE so that there is not an "apples and oranges" comparison with the $37.4/MWh PCA cited by Cowlitz/Clark?

A. Yes. Attachment 9 shows summary information from our 2002 estimate of PGE's "PCA." The first three lines of the table show the production and transmission components of Total Operating Expenses and Return on Rate Base from the Lookback Study Documentation, WP-07-E-BPA-44A at 650. The sum of these components equals Contract System Cost, the numerator in the ASC calculation. The next three lines show Total Retail Load and Distribution Losses, which when summed equal Contract System Load, the denominator in the ASC Calculation. *See* Lookback Study Documentation, WP-07-E-BPA-44A at 651.

In order to determine a comparable "power cost" ASC as defined by Cowlitz/Clark from our 2002 estimate of PGE's ASC, we begin with the production-related component of Total Operating Expenses of $877,995,940. We must subtract from this value costs that are typically not part of a "PCA" such as depreciation, allocated administrative and general expenses, and two items unique to PGE, the BPA REP Reversal and the Oregon Public Purpose Charge. The total of these non-power costs is $139,572,478. Removing the non-"PCA" related costs results in a total "PCA" cost of $738,423,721. Dividing that value by the Contract System Load results in a "PCA" ASC of $37.46, which is within 0.16% of what Cowlitz/Clark said PGE's ASC should be.

Q. What do you conclude from this comparison?

A. This analysis demonstrates, once again, that our method of calculating PGE's ASC is very accurate. In the above example, Cowlitz/Clark's estimate and BPA's estimate of PGE's power costs (adjusted to make the calculations comparable) are almost identical. While neither calculation can alone be used simply as PGE's ASC because of missing costs, this comparison shows that there are no appreciable differences between the power cost component of the backcast ASCs, which are based on FERC Form 1 data, and the power cost component of an ASC based on the jurisdictional rate filing recommended by Cowlitz/Clark.

Section 3.1.3: Backcast ASCs Compared to Other Benchmarks

Q. Are there any other benchmarks that you have evaluated to test whether BPA's backcast ASCs are reasonable in light of Cowlitz/Clark's arguments?

A. Yes. In a statement regarding BPA's reforecast of FY 2002-2006 ASCs, Cowlitz/Clark contend there are several benchmarks to test the reasonableness of ASC results. Schoenbeck and Beck, WP-07-E-JP17-01 at 33. These include: (1) the actual rate paid by the residential customers in this jurisdiction; (2) the rate charged to large power customers in the jurisdiction; and (3) regular reports filed with utility commissions. *Id.* We looked at these three benchmarks to test the reasonableness of our backcast ASCs for the 2002-2008 period.

Q. Addressing the first benchmark, Cowlitz/Clark state that typically residential rate charges contain a substantial portion of distribution-related costs that are not included in ASC determinations. Schoenbeck and Beck, WP-07-E-JP17-01 at 32. Distribution costs would have been in the range of 35-45 percent prior to the energy crisis. Id. More recently, the distribution percent can still be 30 percent of the overall residential rate. Id. Do you agree?

A. Yes. Cowlitz/Clark note the basic construct of the calculation of a utility's ASC, which again is the utility's production and transmission costs.

Q. Did you test this benchmark against the 2002–2006 backcast ASCs?

A. Yes. We compared average actual residential rates for each IOU during the 2002–2006 period as reported in the FERC Form 1s. We first tested to see whether the backcast ASCs tracked the average actual residential rates over time, that is, whether the year-to-year change in the ASC followed the year-to-year change in the actual average residential rates. In virtually all cases, the ASCs moved in the same direction as the actual average residential rates. With PSE there were some lags in the tracking, primarily due, we believe, to its annual Power Cost Adjustment filings with the WUTC. In accordance with

Cowlitz/Clark's testimony, we performed an additional test in which we reduced actual average residential rates by 30 percent to identify an assumed power and transmission portion of residential rates. *See* Schoenbeck and Beck, WP-07-E-JP17-01 at 33.

Q. What did this test indicate?

A. For every IOU except PSE, the 2002–2008 backcast ASCs were either very close to or lower than the actual average residential rate. PSE's average actual rates for the three major customer classes are very similar in value, though the average actual residential rate is lower than the rates for industrial and commercial customers. This may indicate that both industrial and commercial customers are allocated relatively more power costs than residential customers. The results of this test are shown in Table 1 below.

Q. Cowlitz/Clark addressed its industrial rate benchmark by noting the rate charged to large industrial customers provides a second readily available yardstick to measure the reasonableness of BPA's ASC projections. Schoenbeck and Beck, WP-07-E-JP17-01 at 33. Typically, these rates are dominated by power supply – and therefore "exchangeable" – costs. Id. For customers served from the transmission system, the power supply portion (production and transmission costs) will be about 90 percent of the overall rate level. Id. Do you agree with this benchmark?

A. Yes, we agree it can be a useful benchmark.

Q. Did you test the 2002–2006 backcast ASCs using this industrial rate benchmark?

A. Yes. We used the same method used for residential rates to calculate the actual average industrial rate for each IOU during 2002–2006.

Q. What were the results of this test?

A. The backcast ASCs for the 2002–2006 period were consistently very close to the actual average industrial rates, with the exception of PSE. PSE's backcast ASCs were significantly lower than its annual average industrial rates, which may indicate that PSE allocates relatively more exchangeable costs to its industrial rates than do the other IOUs. The results of this test are also shown in Table 1.

Table 1

Residential and Industrial Rate Benchmark Results

	2002	2003	2004	2005	2006
Avista					
Ave. Residential Rates Less 30% Dist.	42.87	43.47	43.87	43.38	45.92
Ave. Residential Rates	61.24	62.10	62.67	61.98	65.60
Ave. Industrial Rates	44.83	43.85	43.49	43.79	45.09
ASC	44.38	44.54	45.77	42.39	44.47
Idaho Power					
Ave. Residential Rates Less 30% Dist.	48.80	43.63	41.92	44.04	41.38
Ave. Residential Rates	69.72	62.33	59.89	62.91	59.12
Ave. Industrial Rates	54.76	40.12	33.52	34.55	29.63
ASC	44.66	37.52	34.21	33.27	28.36
Northwestern					
Ave. Residential Rates Less 30% Dist.	54.41	54.41	57.51	60.28	62.14
Ave. Residential Rates	77.73	77.73	82.16	86.11	88.78
Ave. Industrial Rates	57.18	57.18	69.07	75.04	79.40
ASC	46.99	46.99	50.43	47.50	52.62
PGE					
Ave. Residential Rates Less 30% Dist.	56.33	54.76	56.32	56.69	58.01
Ave. Residential Rates	80.48	78.23	80.46	80.99	82.88
Ave. Industrial Rates	58.15	54.99	55.88	56.51	56.49
ASC	52.54	47.16	44.30	46.99	49.72
Pacific NW					
Ave. Residential Rates Less 30% Dist.	41.25	40.87	39.96	39.72	44.75
Ave. Residential Rates	58.92	58.38	57.09	56.75	63.93
Ave. Industrial Rates	35.88	38.61	38.50	39.21	40.43
ASC	37.65	36.80	39.49	40.74	40.91
Puget Sound Energy					
Ave. Residential Rates Less 30% Dist.	44.21	43.20	43.96	47.03	52.46
Ave. Residential Rates	63.15	61.72	62.80	67.18	74.95
Ave. Industrial Rates	65.49	70.69	71.14	74.20	81.03
ASC	48.05	45.41	46.50	50.21	55.32

Q. Cowlitz/Clark also mention the benefits of the results of operations reports, which are based on commission-approved ratemaking methods. Schoenbeck and Beck, WP-07-E-JP17-01 at 34. Did BPA look at these reports when constructing the backcast ASCs?

A. Yes. We used PacifiCorp's Results of Operation filings to develop its Pacific Northwest allocation of costs. This is described in Boling, *et al.*, WP-07-E-BPA-57 at 11-12.

Q. The Cowlitz/Clark testimony, which described the benchmark tests, was directed at the 2002-2006 ASC forecasts that were used to develop BPA's rate in the WP-02 rate filing. Are these benchmark tests applicable to the 2002-2006 ASC backcasts?

A. Yes. The benchmark tests are a simple metric to show if any ASC, whether it is a forecast or a point-in-time estimate, is reasonable. As described above, the 2002-2006 ASC backcasts fall within the parameters of the benchmarks Cowlitz/Clark has presented.

Section 3.2: Alleged Use of BPA's Proposed 2008 Average System Cost Methodology in Backcast ASCs

Q. What other issues did the parties raise in their direct cases?

A. APAC asserts that we did not use the 1984 ASCM when we produced the backcast ASCs, but instead relied on the proposed 2008 ASCM that was published on February 7, 2008, with only a few "minor or cosmetic changes." Wolverton, WP-07-E-AP-1 at 43.

Q. Do you agree?

A. No. The 2002-2006 ASC backcasts were calculated using the standard ASC cookbook model. This model uses functionalization codes and calculations that substantively comply with the 1984 ASCM. One can also compare the substantive requirements of the 1984 ASCM with the proposed 2008 ASCM. Where there are differences between the two methodologies, we used the 1984 ASCM, not the proposed 2008 ASCM. APAC's statement that we used the new ASCM is, therefore, simply wrong.

Q. Did APAC provide any specific examples of how your backcast ASCs were following the proposed 2008 ASCM rather than the 1984 ASCM?

A. No. As far as we can tell, APAC did not specifically identify why it believed we were applying the proposed 2008 ASCM rather than the 1984 ASCM. A cursory review of the two methodologies does not provide us much guidance either. The backcast ASCs do not include equity or taxes, which conforms to the 1984 ASCM. The proposed 2008 ASCM, however, includes equity and some taxes. APAC claims that this difference is simply a "minor or cosmetic adjustment;" however, eliminating equity and taxes were two of the most significant changes BPA made in developing the 1984 ASCM, and were important enough to significantly reduce utilities' REP benefits compared to BPA's 1981 ASCM. The exclusions of equity and taxes were so significant they were primary reasons for the extensive litigation challenging the 1984 ASCM. Consequently, keeping equity and taxes out of the backcast ASC calculations is neither minor nor cosmetic. APAC fails to point to any way the approach BPA used to calculate the backcast ASCs, which is based on the requirements of the 1984 ASCM, is substantively different than the 1984 ASCM. *See* Wolverton, WP-07-E-AP-1 at 43-45.

Q. Does APAC identify any similarities of your 1984 ASCM-based approach to the proposed 2008 ASCM?

A. APAC's testimony makes general references to a "formula approach" to calculating ASCs, but it is not clear what this "formula approach" means. Wolverton, WP-07-E-AP-1 at 43-45. In clarification, APAC's witness stated that he equated "formula approach" to the use of FERC Form 1 data in the backcast ASCs instead of using a jurisdictional approach to obtain cost data from state commission rate orders. As explained throughout this testimony, however, BPA is using the FERC Form 1 as the source of data for the backcast ASCs only because it is the best available data to estimate the ASCs, not because it has any relationship to the source of data under the proposed

2008 ASCM. The FERC Form 1s have the information necessary to develop an efficient and accurate estimate of the IOUs' ASCs for the seven-year period relevant to this case. That reason alone is why we chose the FERC Form 1 in lieu of filed jurisdictional data as our preferred data source for calculating backcast ASCs.

Q. *APAC contends that BPA has asserted that its 2009 ASC methodology-based estimates are good enough for the Lookback analysis. Wolverton, WP-07-E-AP-1 at 43. Do you agree?*

A. No. We have not made any such statement. This allegation is also refuted by the fact that we have not developed the ASC backcasts based on the substantive requirements of the proposed 2008 ASCM (which APAC calls the "2009 ASCM"). BPA's ASC testimony, Boling, *et al*., WP-07-E-BPA-57, and Manary, *et al*., WP-07-E-BPA-61, describe in detail the ASC cookbook, the changes to the cookbook and our ASC calculations. The changes we made to the model are based upon changes in the utility industry, as well as changes to the FERC Uniform System of Accounts. We established that the changes detailed in our direct testimony are all consistent with the 1984 ASCM and would have been made if the REP had been active. APAC has not provided us with any evidence or arguments to the contrary.

Q. *Did APAC point out any errors that BPA made in the 1984 ASCM calculation and functionalization codes?*

A. No.

Q. *APAC argues that BPA's use of its new ASCM denies preference customers of their right to intervene at the state jurisdictional level or at FERC to protest the ASCs. Wolverton, WP-07-E-AP-1 at 43, erratum. Do you agree?*

A. No. First, as explained above, BPA has not used its proposed 2008 ASCM to develop the backcast ASCs.

Second, BPA is backcasting ASCs for purposes of the WP-07 Supplemental Proceeding. When BPA has previously conducted rate proceedings, BPA has routinely forecast utilities' ASCs. Although parties could present arguments in BPA's rate case about BPA's ASC forecasts, just as they can in the instant proceeding, parties never had the right to appear before a state commission during an investor-owned utility retail rate proceeding, or protest BPA's rate case ASC forecasts before FERC, prior to BPA being able to use its forecast ASCs to develop rates. The intervention rights were reserved to the retail rate filings in the states and the subsequent use of the state order in the ASC determination, and to intervene in the actual ASC filing before FERC. The 2002-2006 period has already occurred and, because BPA and the IOUs were implementing REP Settlement Agreements, the REP was not implemented. Because it was not implemented, ASCs were not developed through the normal REP process. Nevertheless, we must develop ASCs for purposes of this Supplemental Proposal.

Third, as mentioned below in Section 4.5, APAC is being given extensive procedural rights through this proceeding to contest our backcast ASCs. This includes the ability to conduct oral and electronic discovery of our proposal, file direct and rebuttal testimony, file legal memoranda, conduct cross-examination, file initial briefs and briefs on exception, and to present oral argument before the Administrator. These procedural protections exceed those provided to parties in a BPA ASC review during implementation of the REP.

Finally, we note that nothing prohibited APAC or any other utility or trade group from intervening in the state rate proceedings of the IOUs to conduct whatever business they believed was necessary. Given that BPA was not implementing the REP during FY 2002-2006, however, such interventions presumably would have had little relationship to calculating utilities' ASCs under the REP.

Section 3.3: Accuracy of FERC Form 1

Q. Previously, in the discussion of BPA's ASC forecast for FY 2007-2008, WPAG argued that FERC Form 1 data are not the same sort of data that would be used by a utility to set rates. Grinberg, et al., WP-07-E-WA-05 at 36-37. Do you agree?

A. No. FERC Form 1 data are actual financial data, operating data, and other information of IOUs, and are reviewed by FERC on an annual basis. Pacific Northwest IOUs make additional similar filings called "Results of Operations," which indicate how a utility is performing under rates that have been approved by a state regulatory commission. These data are actual results and are taken from the same reporting system that produces the FERC Form 1.

The IOUs' accounting systems are required to conform to the FERC Uniform System of Accounts, which is the same set of accounts used by the state commissions. This system of accounts is also a requirement in the 1984 ASCM. In some jurisdictions, the FERC Form 1 is used as the Results of Operations document.

Q. WPAG contends that by using FERC Form 1 data there is a higher likelihood of data entry errors and other anomalies. Grinberg, et al., WP-07-E-WA-05 at 36-37. Do you agree?

A. No. FERC Form 1s are no longer developed using a separate and antiquated hand entry accounting system. Further, electronic downloading minimizes the likelihood of data entry errors.

Q. WPAG asserts there is no tie-in to the ratemaking process, and no analysis or examination of the data for year to year changes or differences. Grinberg, et al., WP-07-E-WA-05 at 36-37. Please respond.

A. In rate cases where actual data are used, the data are taken from a utility's accounting system, which is based on the FERC Uniform System of Accounts. If the rate case uses year-end calendar information, the data will conform to the data in the FERC Form 1. Again, this is the same system that a utility uses to develop its FERC Form 1 filing.

The FERC Form 1 is considered an industry standard for utility data. A filing includes the actual financial data of the utility, in addition to the operating data for power plants. A filing shows energy balance information that is proof the utility has energy sources to meet all its energy needs. A filing is required by FERC on an annual basis and is reviewed by the Commission. Also, at least one regulatory commission in the region, the Idaho Public Utilities Commission, accepts the FERC Form 1 for the annual Results of Operations filings.

Q. WPAG argues that FERC Form 1 data are updated yearly, whereas under the 1984 ASCM, ASC filings are triggered by the issuance of retail rate orders, which may not occur for years at a time. Grinberg, et al., WP-07-E-WA-05 at 36-37. Is this problematic?

A. No. All it means is that the inherent lag between retail rate orders is not present in our analysis. Also, because most utilities, as noted by Cowlitz/Clark, filed something every year of the rate period, it is reasonable to assume that annual ASCs would likely have been filed by the utilities.

Section 3.4: Updating Price Forecasts for FY 2007-2008 Backcast ASCs

Q. What issues were raised regarding the backcast ASCs you calculated for FY 2007-2008?

A. The IOUs argue that we should use the most current data available when calculating ASCs for purposes of determining reconstructed REP benefits for the Lookback. La Bolle, *et al.,* WP-07-E-JP6-08 at 83. The IOUs argue actual 2007 price data is available for wholesale electricity, natural gas and coal, so there is no need to rely on forecast prices for 2007. *Id.*

Q. *What price data did you use?*

A. We used the gas, market and inflation rates that were used in the WP-07 Final Proposal.

Q. *What reasons do the IOUs give for proposing to change this assumption?*

A. The IOUs' main contention is that the price forecast we are using for escalators is two years out of date.

Q. *Do you agree that this assumption should be changed?*

A. Yes. We will update the 2007-2008 ASC backcast calculations for the final Supplemental Proposal with revised market and gas price actual and forecast tables.

Q. *Did the IOUs request that BPA update any other aspects of the 2007-2008 ASC backcasts?*

A. As far we can tell, no. The IOUs did not raise any other specific objections to our proposed ASC backcasts for these years. The IOUs make some general statements in their testimony about using the "most current data available when determining the ASCs," but do not reference any particular updates besides the market prices for gas, electricity, and coal. La Bolle, et al., WP-07-E-JP6-08 at 83. Nor have we identified any other areas that we would propose to update for the final studies at this point in the case. There may in fact be other areas, but we do not think that any other information would be necessary to accurately estimate the IOUs' backcast ASCs. Adjusting the backcast ASCs for the components described above should be relatively easy and is consistent with the updates BPA typically makes when finalizing studies. Also, the updated market price forecasts should capture most of the price and cost variability that has occurred since the 2006 FERC Form 1 was developed. Taken together, we believe that updating the backcast ASCs for market prices as described above should address any issues created by the passage of time since our original backcast ASC was developed.

Section 4: 1984 ASC Methodology Issues

Q. What other major issues did parties raise in their direct cases?

A. Cowlitz/Clark, WPAG, and APAC argued that our overall approach to calculating the backcast ASCs and the forecasts for 2007-2008 does not comply with the 1984 ASCM. They also all argued that we were not following the 1984 ASCM in various ways.

Section 4.1: Revised ASC Forecasts and Compliance with 1984 ASCM

Q. Did any party file testimony questioning your compliance with the 1984 ASCM when you revised the ASC forecast for the WP-02 rate period?

A. Yes. Cowlitz/Clark argued that our ASC forecasts are wrong because they do not comply with the 1984 ASCM. Schoenbeck and Beck, WP-07-E-JP17-01 at 32.

Q. What specific arguments did Cowlitz/Clark raise?

A. Cowlitz/Clark assert that under the 1984 ASCM, ASC forecasts must have their foundation, or starting point, on costs that have been approved for ratemaking purposes by the appropriate state commission or utility governing body. *Id.* Because BPA's ASCs are not based on these filings, Cowlitz/Clark contends that the ASC forecasts do not comply with the 1984 ASCM. *Id.*

Q. Do you agree?

A. No. Cowlitz/Clark are mistaken that the 1984 ASCM prescribes any particular method or formula for how BPA is supposed to *forecast* ASCs for purposes of setting rates. The 1984 ASCM is silent on this issue. As such, ASC forecasts can be calculated like any other forecasts in the rate case, which use available information and reasonable assumptions. To be clear, the 1984 ASCM plays a critical role in forecasting ASCs, but that does not mean we have to do an exhaustive review of a utility's state regulatory filings to calculate an ASC forecast. Historically, BPA would use the last ASC filed by the utilities as the base year for the forecast. This practice is in no way contrary to the

1984 ASCM because we are not actually setting ASCs when we forecast them in the rate case, but only estimating the ASCs to provide inputs that will be used to establish rates. What the "actual" ASCs end up being is a function of the within-rate period ASC determinations.

BPA's historical method of forecasting ASCs is, in fact, what BPA used for the WP-02 rate period. For the WP-02 ASC forecasts, BPA used the last-filed ASCs from the IOUs for its "base year data" of ASC estimates. These ASCs were then escalated using a forecast model through the rate period and 7(b)(2) period. As explained in Section 2.1.1 above, continuing to use this method along with the forecasting model from the WP-02 rate case makes sense. We have not violated the 1984 ASCM in any way by forecasting ASCs as we have done for the WP-02 rate period.

Q. Did parties raise any particular issues with your compliance with the 1984 ASCM for BPA's FY 2007-2008 forecasts?

A. Yes. WPAG raised some concerns.

Q. What objections did WPAG raise to your proposed forecast ASCs?

A. WPAG alleges that we did not comply with the requirements of the 1984 ASCM because it did not use data from the most recent retail rate filing of each IOU from the relevant period as its data source to forecast the relevant ASC. Rather, we used the FERC Form 1. Grinberg, *et al.*, WP-07-E-WA-05 at 36.

Q. What is your response?

A. The reason we used FERC Form 1 data to forecast the ASCs for the WP-07 rate period was because of staleness of the data used in the WP-02 rate proceeding. The last ASCs that most of the IOUs filed were from the mid-to-late 1990s. In the WP-02 case, these filings were only 2-3 years old when BPA used them to set rates. It was thus reasonable to use them there. By the time BPA commenced its WP-07 case in 2005, these filings were almost ten years old. BPA had very little basis to believe that the information supplied back in 1995-96 period was still pertinent for forecasting ASCs for the 2007-2008 period. BPA believed that a better alternative at the time was to use the utilities' most recent FERC Form 1s, which at the time were for 2004, and then use the 1984 ASCM to estimate an ASC for each IOU. When BPA presented this approach as part of its original rate filing, no party objected. Indeed, WPAG at the time did not object. *See* responses to BPA Data Request No. BPA-JP17-7 and BPA-WA-24 (Attachments 10 and 11). Finally, as explained above, the ASCM does not prescribe any particular method or source for forecasts of ASCs in BPA's power rate cases.

Q. What other issues did the parties raise?

A. APAC claimed that BPA did not have filings from the IOUs of their ASC and therefore does not have a method to calculate Residential Exchange impacts pursuant to the 1984 ASCM. Wolverton, WP-07-E-AP-1 at 33.

Q. Do you agree?

A. No. First, as mentioned above in response to Cowlitz/Clark and WPAG, the 1984 ASCM does not specify what method we must use to forecast ASCs. BPA's rationale for using the approach it did in the WP-02 and WP-07 filings, as described above, applies equally here. Second, if APAC's intent was to state that BPA does not have ASC filings made pursuant to REP contracts that existed in winter/spring 2001, then it is correct – we do not – but this is because the REP was not being implemented at the time and no such filings were made. The absence of such filings, however, was the very reason BPA chose the methods it did to forecast ASCs and to calculate Residential Exchange benefits. As noted above, BPA used an ASC forecasting model, which was never challenged by any party in the WP-02 rate case, to escalate the ASCs.

Section 4.2: Backcast ASCs and Compliance with 1984 ASCM

Q. Did the parties raise any arguments challenging the compliance of BPA's backcast ASCs with the 1984 ASCM?

A. Yes. Cowlitz/Clark, APAC, and WPAG raised issues.

Section 4.2.1: General Compliance with 1984 ASCM

Q. What specific objections did Cowlitz/Clark raise?

A. Cowlitz/Clark argue that BPA ignored the FERC-approved 1984 ASCM in calculating the backcast ASCs by relying upon FERC Form 1 data instead of state commission-approved costs. Schoenbeck and Beck, WP-07-E-JP17-01 at 36.

Q. Do you agree that BPA ignored the 1984 ASCM when calculating the backcast ASCs?

A. Absolutely not. The primary objective, if not only objective, of the 1984 ASCM is to establish an ASC that includes allowable exchangeable costs. When we say "exchangeable" we mean costs that under the 1984 ASCM should be considered in the calculation of an IOU's average system cost. As we started the process of calculating these ASCs, we followed the substantive requirements of the 1984 ASCM to achieve this goal. The 1984 ASCM provides rules governing functionalization methods for determining each exchanging utility's ASC. We used these rules as much as reasonably possible when examining the costs of the utilities in their FERC Form 1s. If there were ambiguous or questionable costs in an underlying FERC account, we took the additional step to reference the FERC's Uniform System of Accounts to evaluate whether the FERC accounts still properly included costs that were exchangeable under the 1984 ASCM. All these steps, and extra steps, were taken to ensure that the resulting backcast ASCs were as accurate as possible.

Q. Did you accurately enter the data into the ASC Cookbook model to calculate the 2002-2006 backcast ASCs?

A. Yes. As described in Boling *et al.*, WP-07-E-BPA-57, 10–11, we used the FERC Form 1 download system to populate appropriate schedules in the ASC Cookbook model.

Section 4.2.2: Use of FERC Form 1

Q. What other arguments did the parties make to support their statements that the backcast ASCs did not comply with the 1984 ASCM?

A. Cowlitz/Clark argues that our use of the FERC Form 1 is not consistent with the 1984 ASCM. *See* Schoenbeck and Beck, WP-07-E-JP17-01 at 35. APAC raises similar concerns in its testimony. *See* Wolverton, WP-07-E-AP-01 at 35-36.

Q. Please respond to these arguments.

A. Our use of the FERC Form 1 has been explained in both the WP-07 initial rate filing and this WP-07 Supplemental Proposal. We used the 1984 ASCM to functionalize costs and calculate the IOUs' ASCs. We went to great lengths to analyze the data within the FERC Form 1 to make reasonable judgments to allocate and functionalize costs. The Lookback Study, WP-07-E-BPA-44 at 74-89, and accompanying Documentation, WP-07-E-BPA-44A at 235-776, extensively detail the analyses we performed. In addition, the actual backcast models were provided in electronic form. The models were populated with FERC Form 1 data, which were electronically downloaded, and include detailed worksheets that demonstrate our conformance to the substantive provisions of the 1984 ASCM.

Q. Why are you using the FERC Form 1 as the data source for purposes of calculating a Lookback ASC?

A. The FERC Form 1 filing is the best source of data to develop the 2002–2008 backcast ASCs for a number of reasons.

First, as noted already in our direct testimony, many of the rate cases that Cowlitz/Clark recommend BPA use end with stipulated settlements. These filings are often silent regarding changes to specific costs, leaving us with little to no real financial information from which to base a utility's ASC. The FERC Form 1, by contrast, provides actual financial and operations data.

Second, using the FERC Form 1 made the backcast ASC estimation process uniform for all of the IOUs. The FERC Form 1 is an industry standard for the reporting of actual utility information for all of the IOUs. Using it as our source information allowed us to maintain consistency in the data as well as consistency in calculating the backcast ASCs. This would not have been the case if we had to review numerous state filings from various jurisdictions that have different reporting and filing requirements. In addition, the FERC Form 1 provides detailed information in the areas of Purchased Power, Sales for Resale and Deferred Asset accounts, which may not be available in certain jurisdictional filings.

Finally, as described more fully below in Section 4.8, the administrative burden of compiling and reviewing state jurisdictional filings for six IOUs – two of which operate in two jurisdictions and one operating in *three* jurisdictions – for the span of seven years would have been enormous. It would have required an immense commitment of BPA's and the parties' resources and time. In our view, the cost of undertaking this massive process far outweighed any benefit that may have been gained. Indeed, as described in Section 3.1.1 above, the overall impact on the ASCs of our use of the FERC Form 1 when compared to known jurisdictional data is relatively low. The comparisons described in Section 3.1.1 confirmed our original position that the FERC Form 1 was a reasonable substitution for the jurisdictional filings of the utilities.

Section 4.3: Exchange Load

Q. APAC argues that BPA does not rely on Residential Exchange loads that normally would be established pursuant to the 1984 ASCM, and is using instead its own projections of Residential Exchange load. Wolverton, WP-07-E-AP-1 at 35. Do you agree?

A. No. As stated before, BPA did not receive ASC filings from the IOUs during the 2002-2006 forecast period. However, we received forecasts from the IOUs of total retail load and residential load for the rate period and 7(b)(2) period.

For the 2002-2006 backcast ASCs we used actual total retail load (Contract System Load under the 1984 ASCM) to determine annual ASCs for each IOU. In addition, we calculated actual exchange loads for each utility. We added five percent to both Contract System Loads and exchange loads to compensate for distribution losses.

Q. How did you calculate exchange loads for each utility during the 2002-2006 period?

A. We obtained each utility's loads by rate schedule data from the FERC Form 1 download system. From the data, we segregated the residential loads and the irrigation loads.

Q. How did you calculate the exchange load forecasts for each utility?

A. We calculated a Residential Load factor for each IOU by dividing the 2006 exchange loads by the Contract System Loads. We then applied this factor to the Contract System Load forecast.

Q. What source did you use for each IOU's Contract System Load forecast?

A. We used the BPA Loads and Resources Information System, which is used to develop BPA's "White Book" of regional utility loads and resources.

Q. Do the IOUs submit their load forecasts on an annual basis to BPA?

A. Yes. BPA receives load forecast data from the IOUs through the Pacific Northwest Utilities Conference Committee (PNUCC).

Section 4.4: New Large Single Loads

Q. APAC argues that BPA omits the statutorily required adjustments to the ASCs for New Large Single Loads. Wolverton, WP-07-E-AP-1 at 36. Please respond.

A. We acknowledge that the ASCs contained in the Supplemental Proposal did not incorporate adjustments for New Large Single Loads (NLSLs). In preparing the Supplemental Proposal, we did not have enough time to research the load data of BPA's utility customers in order to make NLSL adjustments. However, we are currently developing a revised ASCM through a regional consultation proceeding. As part of such development, we are conducting an expedited review of exchanging utilities' ASC under the proposed ASCM. Parties have intervened in the expedited ASC review process. As part of the expedited review, we are gathering information to identify NLSLs for each exchanging utility. If NLSLs are identified in that process, we will incorporate the results in this process and exclude the cost of serving such loads from utilities' ASCs in accordance with the 1984 ASCM.

Q. If BPA discovers any NLSLs in the expedited review process, and removes the costs and loads pursuant to the 1984 ASCM, what likely impact will this have on the ASCs?

A. Though we have not done an exhaustive study, our general analysis indicates that with the exception of Avista for the years 2005 and 2006, the cost of resources used to serve NLSLs for all other utilities were less than the utility's ASC. This means that if and when we discover any NLSLs, and then adjust the ASCs for these NLSLs, in many instances it will likely either increase or result in no overall change to the ASCs developed in this case.

Section 4.5: Procedural Rights

Q. APAC argues that BPA's customers and intervenors have been denied their procedural rights to question the ASC filings as required by the 1984 ASCM. Wolverton, WP-07-E-AP-1 at 36, 46. Do you agree?

A. BPA's customers and intervenors have not been denied their procedural rights to question the ASC filings as required by the 1984 ASCM given the context of the WP-07 Supplemental Proceeding. As noted previously, BPA did not implement the REP during the Lookback period and therefore did not conduct the ASC review proceedings in which interested parties could have participated and exercised their procedural rights under the 1984 ASCM. We, however, are not establishing utilities' ASCs for purposes of implementing the REP. When BPA once again begins implementing the REP on October-1, 2008, all parties will receive their full procedural rights for the establishment of utilities' ASCs that will be used to determine REP benefits. Instead, we are currently estimating ASCs based on the best information available for use in the Supplemental Proposal. Because we are estimating ASCs for purposes of the Supplemental Proposal, the parties to this proceeding are provided procedural rights far exceeding those provided under the 1984 ASCM. Parties in ASC review proceedings generally conducted limited written discovery and filed issue lists containing their arguments on ASC issues. In the instant proceeding, in contrast, parties are provided clarification discovery, electronic discovery, the opportunity to file direct testimony, the opportunity to file rebuttal testimony, the opportunity to file legal memoranda to accompany their testimonies, the opportunity for cross-examination, the opportunity to file initial briefs and briefs on exception, and the opportunity for oral argument. Parties therefore have procedural rights far exceeding their previous rights in ASC reviews.

Section 4.6: Transmission Adjustment

Q. Did Clark/Cowlitz, WPAG or APAC raise any other issues that have not previously been addressed?

A. Yes. WPAG notes that our 2002-2008 backcast and 2007-2008 forecast ASCs do not have an adjustment for transmission as required by the 1984 ASCM. Grinberg, *et al*., WP-07-E-WA-05 at 44-45 and WP-07-E-WA-05-E1.

Q. Is this correct?

A. Yes.

Q. Are you planning to adjust the 2002-2008 backcast and 2007-2008 forecast ASCs to account for the transmission limitation noted in the 1984 ASCM?

A. Yes. We will make adjustments to the 2002-2008 ASC backcasts and the revised 2007-2008 ASC forecasts that were published in the Supplemental Proposal.

Q. WPAG recommends using an 18 percent factor to allocate transmission plant and cost to distribution. Grinberg, et al., WP-07-E-WA-05 at 44. Do you support this factor?

A. We will review the data WPAG submitted as well as any other relevant evidence filed on this issue. We will adjust Transmission Plant and Transmission expenses in the final Supplemental Proposal to be consistent with the 1984 ASCM.

Q. WPAG states that to remedy this omission BPA should obtain the pertinent jurisdictional retail rate filings as the data source for their IOU ASC forecasts and backcasts, and correctly apply the 1984 ASCM to the transmission plant and related expenses. Grinberg, et al., WP-07-E-WA-05 at 45. Do you agree?

A. No. As explained above, BPA's approach to calculating the backcast ASCs is reasonable. After allocating some percentage of transmission costs to distribution, as discussed above, ASCs will be lowered. We have shown that using the FERC Form 1 produces results that are either lower than or very close to jurisdictional ASC determinations. In addition, we have shown that BPA's 2007 ASC backcast is significantly lower than Cowlitz/Clark's 2007 "PCA ASC" for Puget Sound Energy. We have also shown the 2002-2006 ASC backcasts to be reasonable even compared with the benchmarks proposed by Cowlitz/Clark (*see* Sections 3.1.2 and 3.1.3 above).

Section 4.7: Other Alleged Deviations

Q. Cowlitz/Clark argue that under the 1984 ASCM, each utility is responsible for making the necessary ASC filing after a commission ruling and BPA should have requested the necessary submittals and accompanying workpapers from the utilities for the backcast ASCs. Schoenbeck and Beck, WP-07-E-JP17-01 at 36. Do you agree?

A. No. Cowlitz/Clark ignore the critical fact that BPA was not implementing the REP with exchanging utilities during the Lookback period. Thus, BPA did not have RPSAs with exchanging utilities. Because BPA was not implementing the REP, BPA had no contractual basis on which to require utilities to file proposed ASCs. Furthermore, because there was no REP, BPA could not conduct the 210-day review processes that would normally occur under the 1984 ASCM. The IOUs were participating in REP Settlement Agreements, not in the REP, during the Lookback period. Also, after nearly all exchanging utilities had terminated participation in the REP by 1996, BPA disbanded its REP implementation staff. During the Lookback period, BPA no longer had the quantity and quality of staff that previously had been dedicated to ASC reviews. To the extent Cowlitz/Clark suggest BPA should have required the utilities to make ASC filings when we began preparing the WP-07 Supplemental Proposal, such a suggestion makes little sense for the reasons previously cited. BPA had no basis upon which to require utilities to file ASCs with BPA. Similarly, BPA had no REP implementation staff to review such filings. Furthermore, in order to develop a Supplemental Proposal and respond to the Court's decisions promptly, BPA had no time to solicit ASC filings, receive the filings, and review the filings in order to incorporate them into the

Supplemental Proposal. Because BPA could not require utilities to file ASCs, it was reasonable, indeed necessary, for us to take on the responsibility of calculating ASCs.

Further, and implicit in the foregoing discussion, in the highly unlikely event utilities had voluntarily provided BPA with ASC filings, we would have had to carefully review such filings for conformance with the 1984 ASCM. We could not simply have relied on the utilities to ensure the underlying data was accurate, or whether the functionalization of the data complied with the 1984 ASCM. We chose to determine ASCs itself because BPA is a neutral party in, and can make decisions on functionalizations that are consistent with the ASCM and based on publicly available data.

Q. *Cowlitz/Clark note that BPA used the FERC Form 1 annual filings from the utilities to calculate backcast ASCs. Schoenbeck and Beck, WP-07-E-JP17-01 at 36. Cowlitz/Clark argue that the 1984 ASCM allows for an ASC to change only if in fact there has been a commission-approved rate change. Id. The 1984 ASCM does not require that a filing be made each and every year. Id. The ASC derived from the last authorized ruling is in place until there is another ruling from the state commission, and all of the IOUs had commission approved rates before June 2001. Id. Please respond.*

A. It is true that the 1984 ASCM required ASC filings based on retail rate changes, which may or may not occur every year. Cowlitz/Clark continues to ignore, however, that the REP was not being implemented during the Lookback period. BPA did not receive any ASC filings from regional utilities, and could not have required utilities to provide BPA with such filings. In such circumstances, it is not critical that the 1984 ASCM requires ASC filings based on retail rate changes because BPA received no filings based on such changes.

Cowlitz/Clark noted in testimony and a data response that Puget Sound Energy had seven rate cases that its witnesses participated in for clients during the 2002-2007 period. Schoenbeck and Beck, WP-07-E-JP17-01 at 35. Three of the filings were general rate cases and the other four filings were Power Cost Adjustment cases. Response to Data Request No. BPA-JP17-4 (Attachment 12). In each case, BPA would have conducted a 210-day process to review and establish PSE's ASC. With the benchmark tests and the frequency of PSE's filings during the Lookback period, one can assume our annual backcast determinations consolidated the overlapping rate filings. Taking into consideration the benchmark tests BPA has done for this testimony, our backcast ASCs are reasonable.

Q. Cowlitz/Clark disagree with BPA's statement that it would have been necessary to intervene in each and every proceeding before the state commissions in order to obtain the necessary information. Schoenbeck and Beck, WP-07-E-JP17-01 at 36-37. Cowlitz/Clark claim this is incorrect because the 1984 ASCM includes a discovery process that allows all parties – including BPA – the opportunity to seek clarification or further support on any cost proposed by the utility to be "exchangeable" and part of the ASC determination. Id. Cowlitz/Clark claim that because the 1984 ASCM was approved by FERC, there really is no need to intervene in the state rate proceeding. Id. Do you agree?

A. No. Although BPA and intervenors have the ability to seek clarification of cost information during BPA's 210-day review processes, such discovery does not replace the assistance gained by intervening in state commission retail rate proceedings. The very filings Cowlitz/Clark point to – unbundling filings for PGE and PacifiCorp – are excellent examples of filings in which a party would benefit greatly from intervention. Such filings addressed significant changes in the utility industry, and intervention would have afforded a party a much fuller contextual and factual environment than would be gained by reading a rate order or seeking clarification from the utility. When the REP was active under the 1984 ASCM, BPA routinely intervened in regional utility rate proceedings to better understand how costs were developed and treated within the filing. The change from the 1981 to the 1984 ASCM did not eliminate the value of intervening in and participating in utilities' retail rate proceedings.

Section 4.8: Alternatives to BPA's Approach

Q. How do Cowlitz/Clark and WPAG recommend BPA calculate ASCs?

A. Cowlitz/Clark propose that the IOUs submit ASCs for each set of rates in place during the period of October 2001 through the present. Schoenbeck and Beck, WP-07-E-JP17-01 at 37. Cowlitz/Clark then propose to allow all parties full discovery rights under the 1984 ASCM to analyze and question the determination with filed comments. *Id*. Cowlitz/Clark then recommend that BPA issue a final determination on each ASC which can then be used in the Lookback analysis. *Id*.

WPAG similarly suggests that we collect the actual data submitted to each utility's regulatory commission when the utilities changed rates during the FY 2002-2006 and FY 2007-2008 periods, and apply the 1984 ASCM to that data. *See* Grinberg, *et al*., WP-07-E-WA-05 at 44.

Q. Are these reasonable proposals?

A. No. As noted previously, BPA does not have any RPSAs with any regional utilities under which BPA has rights and obligations regarding the implementation of the REP. BPA simply cannot order the IOUs to submit ASC filings to BPA in the absence of the RPSA. Also, the administrative expense and burden if we attempted this approach would be overwhelming. Each utility (there are six IOUs alone, three of which have service territory in multiple jurisdictions) would have to develop an ASC filing for *every* state PUC retail rate order that resulted in a rate change issued during the past seven years in every applicable regional state jurisdiction. Each ASC filing would have to contain all the necessary schedules and studies as dictated by the 1984 ASCM.

Q. How many ASC filings would this likely include?

A. We have not done an exhaustive search, but our preliminary findings indicate that the state commissions issued approximately 77 rate change orders for the IOUs over the past seven years that would have triggered an ASC review. *See* Attachment 13, which lists the rate orders that would have triggered ASC filings.

Q. What would the parties and you have to do with each of these rate orders to comply with Cowlitz/Clark's and WPAG's recommendation?

A. For *each* filing, we would have to initiate a 210-day review proceeding and follow the procedural time table prescribed by the 1984 ASCM. In the many proceedings, which would presumably have to occur *simultaneously*, we, and intervenors in the ASC proceedings, would have opportunities to request information and raise issues. Our access to information may be limited due to changes in staffing at the IOUs and the vintage of the data. We then would have to draft ASC reports for each individual ASC filing by each utility in each applicable state jurisdiction. As is obvious, such a proposal is simply impractical.

Q. How long would this process likely take?

A. If BPA were to use its current staff (namely, this panel) to process the ASC filings, the process could span several years. BPA has far less staff now assigned to the ASC review than historically when the REP was operating. During the historical operation of the REP, BPA had approximately 40 BPA and contractor staff devoted full time to the ASC review process. But even then, staff only had to review the contemporaneous ASC filings of the IOUs. BPA has never in its history had to process 77 ASC filings at one time.

BPA, theoretically, could attempt to significantly increase its costs and hire an enormous amount of staff to attempt to process these rate orders. But even if that administrative burden were reasonable, which we believe it is not, it is highly unlikely that knowledgeable experts could be readily found. The last official ASC review process conducted in the Northwest for the IOUs was in the mid-1990s. Over a decade has passed since BPA or any other utilities have engaged experts and staff to evaluate ASCs. Thus, BPA would likely have to rely on the few staff experts and staff that had never conducted an ASC review process. This means BPA would have to spend even *more* time and resources training the new staff.

Q. Would this administrative burden be only on BPA?

A. Absolutely not. The IOUs and COUs would also have to expend resources to participate in this process. Although we do not know the relative preparedness of the parties to conduct these proceedings, we believe it is a reasonable assumption to assume that if the last filed ASC was in the mid-1990s, it is very likely that neither the IOUs nor the COUs are prepared to conduct reviews. Even if they were, it is highly unlikely any of them could even attempt to participate in 77 simultaneous filings. Consequently, they too would have to expend significant resources to participate in the review processes.

Q. Even if BPA could find the resources and the staff to implement Cowlitz/Clark's alternative, what other problems than administrative burdens do you see?

A. We think the historical nature of the data that would have been reviewed in this process would have made checking the accuracy of the filed ASCs very difficult and laborious. Under the traditional ASC review process, the source of data used in an IOU's Appendix 1 was from the record of the last rate order that changed the utility's rates. These orders were generally contemporaneous with the Appendix 1 filings. If information was not available or evident from the record, parties could request it through the discovery process. Because the ASCs were developed from data related to a recent rate filing and order, the utility likely had the data available.

In this case, however, most of the ASCs being reviewed are *not* from contemporaneous rate orders. Rather, BPA and the parties would have to sift through old rate orders and records to evaluate the ASCs. The fact that seven years have passed in some instances from the original rate order is going to be a significant issue in the ability of BPA and the parties to receive data relevant to an IOU's ASCs. Data that may have been reasonable to keep for a year or two after a rate order may have been discarded, destroyed, or simply lost after it failed to be useful. Consequently, we foresee the dated nature of the data underlying the ASCs is going to compound the difficulty of conducting the 210-day review process, and would likely have an adverse effect on BPA's (and the parties') ability to accurately review the ASCs submitted by the IOUs.

Q. *Do you think your approach is a more reasonable alternative?*

A. Yes. As we have demonstrated above, there are numerous indicators that suggest there would be very little difference in the 2002–2006 backcast ASCs and the ASCs produced using the Cowlitz/Clark and WPAG alternative. As stated above in Sections 3.1.2 and 3.1.3, when using the benchmark test that Cowlitz/Clark has described, our backcast ASCs are reasonable. When testing to see if the FERC Form 1 data produces reasonable ASCs in comparison to ASC filings in the mid 1990s by the IOUs, the use of the FERC Form 1 data produce reasonable results. We think it is remarkably unreasonable to turn to an approach that is immensely burdensome, time-consuming, and wasteful when quality data is readily available and can be used in accordance with the substantive requirements of the 1984 ASCM to estimate highly accurate ASCs for the Lookback period.

Q. *What is Cowlitz/Clark's remedy if the IOUs were unable or unwilling to go through this process?*

A. Cowlitz/Clark's proposed remedy is to have the IOUs forfeit any REP settlement payments provided to that entity if it fails to file. Schoenbeck and Beck, WP-07-E-JP17-01 at 37.

Q. Is this a reasonable remedy?

A. No. First, given the absence of RPSAs and BPA's inability to immediately implement the REP, it would be unfair to penalize a utility for failing to do what it is not required to do. Second, REP benefits must be passed through to the utility's residential and small farm consumers. Eliminating such benefits harms the residential consumers, not the utilities.

Q. Does this complete your testimony?

A. Yes.

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Request Detail

Request ID: BPA-WA-21
Page Number: 40-41
Line Number: 18-6
Exhibit Filing: WP-07-E-WA-01

Contact Name: Paul McClain
Contact Phone: 503.230.5489
Contact Email: pwtmcclain@bpa.gov

Request Text: Please provide all documents, workpapers and analyses used to calculate Clark Public Utilities' ASC for years 2002 through 2006.

Response Detail

Date Response Filed: 4/18/2008 1:30:23 PM
Contact Name:
Contact Phone:
Contact Email:
Response Text:
The calculation started with numbers from Clark Public Utilities' September 2005 ASC filing (attached). To estimate what the ASCs would have been for the 2002-2006 period, we adjusted three things: 1) the price of natural gas was adjusted to Clark's actual average price of gas in each year, 2) power purchased from BPA was adjusted by the results of BPA's current rate case modeling, and 3) all other costs were adjusted downward to account for inflation. The attached spreadsheet shows the calculations. This was an estimate rather than a precise determination of what the ASCs would have actually been. New estimates or actual values were not calculated for loads or costs other than as described above.
Files Submitted for this Response:
BPA-WA-21.zip

Calculation of Revised Clark ASC
3/28/2008

From COSA Used in ASC Filing	ASC	FY02	FY03	FY04	FY05	FY06
Bonneville Power Administration	75,549,242	74,285,791	74,285,791	74,285,791	74,285,791	74,285,791
River Road Generating Plant	110,206,073	72,816,508	69,784,218	65,509,933	80,362,218	110,206,073
Total of BPA and Fuel	185,755,315	147,102,299	144,070,008	139,795,724	154,648,008	184,491,864
Inflation Rates (from BPA Lookback)			2.1%	2.9%	3.2%	3.2%
Non-BPA and Fuel Portion of ASC	17.59	15.72	16.05	16.52	17.04	17.59

Revised for 7b2 Rate Case ASC	Purchased Power	Estimated ASC				
Purchased Power Cost	Output from ASC	FY02	FY03	FY04	FY05	FY06
Bonneville Power Administration	75,549,242	74,285,791	74,285,791	74,285,791	74,285,791	74,285,791
River Road Generating Plant	141,217,539	103,827,974	100,795,683	96,521,399	111,373,684	141,217,539
RRGP Replacement Energy Purchases	-	-	-	-	-	-
Market Energy/Cap. Purchases	-	-	-	-	-	-
Williams Energy	3,195,647	3,195,647	3,195,647	3,195,647	3,195,647	3,195,647
S&I Services	10,471,545	10,471,545	10,471,545	10,471,545	10,471,545	10,471,545
Transmission Expenses	13,515,629	13,515,629	13,515,629	13,515,629	13,515,629	13,515,629
Total Power Costs	243,949,602	205,296,585	202,264,295	197,990,010	212,842,295	242,686,150
Power Costs w/o BPA and Fuel	58,194,287					

	Orig. FY06 Filing	FY02	FY03	FY04	FY05	FY06
ASC	59.00	48.51	48.17	47.68	51.51	58.72
Exchange PF	46.27	39.95	42.00	38.40	38.88	40.29
Residential Loads incl. losses (MWH)	2,376,287	2,133,100	2,147,177	2,258,948	2,268,654	2,376,287
Estimated Exchange Benefits	$ 30,250,138	$ 18,260,323	$ 13,249,357	$ 20,954,134	$ 28,663,478	$ 43,794,977

Fiscal Year 2002	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May
Cost (Cents per Therm)	55.4	64.3	55.2	55.0	54.8	55.2	55.2	0.0
Plant Fuel Consumption	12,896,860	10,331,490	12,945,250	13,060,600	11,792,790	12,919,280	802,220	0
	$ 7,147,344	$ 6,643,214	$ 7,140,048	$ 7,177,195	$ 6,463,815	$ 7,130,986	$ 442,424	$ -

Fiscal Year 2003	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May
Cost (Cents per Therm)	54.1	53.7	53.9	53.7	53.5	55.6	0.0	0.0
Plant Fuel Consumption	13,065,910	12,762,760	13,182,430	13,190,420	11,912,490	10,794,220	0	0
Total Cost	$ 7,074,232	$ 6,849,268	$ 7,099,731	$ 7,080,681	$ 6,371,162	$ 6,005,504	$ -	$ -

Fiscal Year 2004	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May
Cost (Cents per Therm)	54.0	54.0	53.7	53.6	53.8	53.9	45.0	0.0
Plant Fuel Consumption	12,808,150	12,722,090	13,188,580	13,124,060	12,141,540	12,912,110	12,195,070	0
Total Cost	$ 6,918,246	$ 6,868,855	$ 7,084,939	$ 7,038,071	$ 6,534,910	$ 6,957,994	$ 5,493,425	$ -

Fiscal Year 2005	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May
Cost (Cents per Therm)	48.9	48.6	50.9	75.2	75.1	40.0	56.6	68.0
Plant Fuel Consumption	12,840,540	11,905,080	13,140,010	13,136,810	11,836,720	10,333,720	12,583,860	1,322,990
Total Cost	$ 6,276,950	$ 5,787,491	$ 6,689,586	$ 9,881,104	$ 8,894,464	$ 4,137,998	$ 7,126,222	$ 900,189

Fiscal Year 2006	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May
Cost (Cents per Therm)	78.0	77.0	47.2	100.5	99.7	0.0	0.0	0.0
Plant Fuel Consumption	12,801,720	12,494,970	8,024,060	12,757,170	11,635,150	0	0	0
Total Cost	$ 9,981,372	$ 9,622,027	$ 3,784,356	$ 12,814,589	$ 11,604,026	$ -	$ -	$ -

Fiscal Year 2002	Jun	Jul	Aug	Sep	Annual	
Cost (Cents per Therm)	0.0	55.2	55.2	56.0	56.1	$ 5.61
Plant Fuel Consumption	0	3,012,510	12,808,570	11,852,570	102,422,140	
	$ -	$ 1,661,399	$ 7,065,360	$ 6,635,573	$ 57,507,359	
Fiscal Year 2003	Jun	Jul	Aug	Sep	Annual	
Cost (Cents per Therm)	55.2	50.8	54.3	55.1	53.8	$ 5.38
Plant Fuel Consumption	530,310	12,737,570	12,697,120	11,275,970	112,149,200	
Total Cost	$ 292,466	$ 6,467,025	$ 6,898,031	$ 6,208,545	$ 60,346,644	
Fiscal Year 2004	Jun	Jul	Aug	Sep	Annual	
Cost (Cents per Therm)	0.0	46.8	44.7	44.7	50.5	$ 5.05
Plant Fuel Consumption	0	11,927,100	12,584,180	12,326,930	125,929,810	
Total Cost	$ -	$ 5,580,732	$ 5,623,990	$ 5,510,307	$ 63,611,470	
Fiscal Year 2005	Jun	Jul	Aug	Sep	Annual	
Cost (Cents per Therm)	64.9	75.5	72.9	74.0	62.0	$ 6.20
Plant Fuel Consumption	358,150	12,857,760	11,097,330	10,984,290	122,397,260	
Total Cost	$ 232,327	$ 9,710,582	$ 8,084,500	$ 8,122,957	$ 75,844,368	
Fiscal Year 2006	Jun	Jul	Aug	Sep	Annual	
Cost (Cents per Therm)	36.0	114.8	85.0	86.9	85.0	$ 8.50
Plant Fuel Consumption	885,240	4,857,330	12,843,040	11,564,170	87,862,850	
Total Cost	$ 318,276	$ 5,577,195	$ 10,915,970	$ 10,046,067	$ 74,663,878	

	Historic PF	Rate Case PF
FY02	28.9	28.81
FY03	30.8	28.81
FY04	30.1	28.81
FY05	28.8	28.81
FY06	27.9	28.81
	29.3	28.81

	Ld. Fcst. File Schedule 7
Oct-01	155,870,148
Nov-01	197,252,193
Dec-01	232,500,783
Jan-02	239,188,283
Feb-02	223,981,815
Mar-02	203,114,819
Apr-02	182,259,088
May-02	162,584,417
Jun-02	138,129,570
Jul-02	134,182,575
Aug-02	136,923,845
Sep-02	129,491,000
Oct-02	153,947,830
Nov-02	204,339,385
Dec-02	233,582,900
Jan-03	229,060,655
Feb-03	201,320,170
Mar-03	184,183,595
Apr-03	170,692,230
May-03	148,072,730
Jun-03	133,480,512
Jul-03	135,958,577
Aug-03	134,769,920
Sep-03	129,671,183
Oct-03	157,833,250
Nov-03	204,079,278
Dec-03	266,155,505
Jan-04	274,600,855
Feb-04	210,885,075
Mar-04	179,918,665
Apr-04	159,640,060
May-04	135,841,075
Jun-04	136,028,750
Jul-04	143,180,855
Aug-04	140,827,720
Sep-04	136,053,030
Oct-04	160,325,630
Nov-04	205,850,585
Dec-04	248,658,785
Jan-05	252,832,905
Feb-05	207,346,565

Sch 7	FY02	FY03	FY04	FY05	FY06	FY07
Oct-Dec	585,623,123	591,870,115	628,068,033	614,835,000	655,286,115	671,381,650
Jan-Sep	1,549,855,411	1,467,209,572	1,516,976,085	1,536,259,380	1,611,559,960	
Total	2,135,478,534	2,059,079,687	2,145,044,118	2,151,094,380	2,266,846,075	
	99.7%	98.3%	100.6%	98.2%	99.3%	
	CY02	CY03	CY04	CY05	CY06	
Sch.7	2,141,725,526	2,095,277,604	2,131,811,085	2,191,545,495	2,282,941,610	
Annual Report	CY02	CY03	CY04	CY05	CY06	
Residential	2,065,000	2,109,000	2,167,000	2,231,000	2,310,000	
Converted	FY02	FY03	FY04	FY05	FY06	
Residential	2,058,977	2,072,565	2,180,451	2,189,821	2,293,714	
w/losses	2,133,100	2,147,177	2,258,948	2,268,654	2,376,287	

Mar-05	190,486,230
Apr-05	172,977,605
May-05	144,131,385
Jun-05	141,120,445
Jul-05	139,282,175
Aug-05	143,384,500
Sep-05	144,697,570
Oct-05	163,879,655
Nov-05	224,463,670
Dec-05	266,942,790
Jan-06	252,293,610
Feb-06	229,118,650
Mar-06	217,010,250
Apr-06	176,371,350
May-06	146,626,165
Jun-06	151,570,525
Jul-06	145,767,265
Aug-06	146,433,430
Sep-06	146,368,715
Oct-06	171,282,150
Nov-06	227,181,800
Dec-06	272,917,700

LAST APPROVED

Clark Public Utilties

TEST PERIOD:
BPA DOCKET NO. current file
JURISDICTION: jurisdiction
LAST APPROVED FILE NUMBER last file
ANALYST NAME: analyst
DATE REPORT DUE:
DOLLARS IN units

Data Matrix

(1) Account Description	(2) Account No.(s)	(3) Funct. Method	(4) Total	(5) Production	(6) Transmission	(7) Distribution/ Other	(8) Math Check
Schedule 1 (Report Page 1 of 2)							
Production Plant:							
Steam Production	310-316	DIR-P	0	0	0	0	0
Nuclear Production	320-325	DIR-P	0	0	0	0	0
Hydraulic Production	330-336	DIR-P	0	0	0	0	0
Other Production	340-346	DIR-P	0	0	0	0	0
Other Production	340-346	DIR-P	0	0	0	0	0
Other Production	340-346	DIR-P	0	0	0	0	0
Other Production	340-346	DIR-P	0	0	0	0	0
Total Production Plant			0	0	0	0	0
Transmission Plant:							
Transmission Plant	350-359	DIR-T	0	0	0	0	0
Other Transmission	Acct. No.	DIR-T	0	0	0	0	0
Other Transmission	Acct. No.	DIR-T	0	0	0	0	0
Total Transmission Plant	350-359		0	0	0	0	0
Total Distribution Plant	360-373	DIR-D	0	0	0	0	0
Intangible Plant	301	PTD	0	0	0	0	0
Intangible Plant	302	PTD	0	0	0	0	0
Intangible Plant	303	PTD	0	0	0	0	0
General Plant:	389-399						
Land and Land Rights	389	PTD	0	0	0	0	0
Land and Land Rights	389	10%PTD	0	0	0	0	0
Structures and Improvements	390	PTD	0	0	0	0	0
Structures and Improvements	390	10%PTD	0	0	0	0	0
Furniture and Equipment	391	Labor	0	0	0	0	0
Furniture and Equipment	391	10%LABOR	0	0	0	0	0
Transportation Equipment	392	TD	0	0	0	0	0
Transportation Equipment	392	10%TD	0	0	0	0	0
Stores Equipment	393	PTD	0	0	0	0	0
Tools and Garage Equipment	394	PTD	0	0	0	0	0
Laboratory Equipment	395	PTD	0	0	0	0	0
Power Operated Equipment	396	TD	0	0	0	0	0
Communication Equipment	397	PTD	0	0	0	0	0
Miscellaneous Equipment	398	DIR-D	0	0	0	0	0
Other Tangible Property	399	PTD	0	0	0	0	0
Total General Plant	389-399		0	0	0	0	0
Total Electric Plant In-Service			0	0	0	0	0
Less - Depreciation and Amortization:							
Steam Plant	108	DIR-P	0	0	0	0	0
Nuclear Plant	108	DIR-P	0	0	0	0	0
Hydraulic Plant	108	DIR-P	0	0	0	0	0
Other Production Plant	108	DIR-P	0	0	0	0	0
Other Production Plant	108	DIR-P	0	0	0	0	0
Other Production Plant	108	DIR-P	0	0	0	0	0
Other Production Plant	108	DIR-P	0	0	0	0	0
Other Production Plant	108	DIR-P	0	0	0	0	0
Intangible Plant	108	PTD	0	0	0	0	0
Transmission Plant	108	DIR-T	0	0	0	0	0
Other Transmission Plant	108	DIR-T	0	0	0	0	0
Other Transmission Plant	108	DIR-T	0	0	0	0	0
Other Transmission Plant	108	DIR-T	0	0	0	0	0
Distribution Plant	108	DIR-D	0	0	0	0	0
General Plant	108	GP	0	0	0	0	0
Other Amortization	Acct. No.	Funct. Code	0	0	0	0	0
Amort. Reserve	111	PTD	0	0	0	0	0
Total Depreciation and Amortization			0	0	0	0	0
Total Net Electric Plant In-Service			0	0	0	0	0
Schedule 1 (Report Page 2 of 2)							
Add - Debits:							
Cash Working Capital		Direct	0	0	0	0	0
Plant Held Future Use	105	PTDG	0	0	0	0	0
Completed Construction	106	PTD	0	0	0	0	0
CWIP	107-120.1	DIR-D	0	0	0	0	0
Acquisitions Adjustments	114	LABOR	0	0	0	0	0
Nuclear Fuel	120.2-120.4	DIR-P	0	0	0	0	0
Investments	123	DIR-D	0	0	0	0	0
Other Investment	124	DIR-D	0	0	0	0	0

Weatherization Investment	0	DIR-P	0	0	0	0	0
Fuel Stock	151-152	DIR-P	0	0	0	0	0
Materials and Supplies	153-157,163	TDG	0	0	0	0	0
Clearing Accounts	184	LABOR	0	0	0	0	0
Misc. Deferred Debits	186	LABOR	0	0	0	0	0
Other Debits	182	Funct. Code	0	0	0	0	0
Prepayments	165	DIR-D	0	0	0	0	0
Total Debits			0	0	0	0	0
Less - Credits:	252-283						
Cust. Advances for Const.	252	DIR-D	0	0	0	0	0
Other Deferred Credits	253	DIR-D	0	0	0	0	0
Accum Def. Inv. Tax Credit	255	DIR-D	0	0	0	0	0
Deferred Gain - Disposition	256	PTDG	0	0	0	0	0
Unamortized Gain - Reacq.	257	PTDG	0	0	0	0	0
Accum. Def. Income Taxes	281-283	DIR-D	0	0	0	0	0
Other Credits	Acct. No.	Funct. Code	0	0	0	0	0
Other Credits	Acct. No.	Funct. Code	0	0	0	0	0
Total Credits			0	0	0	0	0
Total Rate Base			0	0	0	0	0
Rate of Return	0.00%						
Schedule 3 (Report Page 1 of 2)							
Production Expense:							
Steam - Fuel Exp.	501	DIR-P	0	0	0	0	0
Steam - Operations Exp.	500,502	DIR-P	0	0	0	0	0
Steam - Maintenance	510-514	DIR-P	0	0	0	0	0
Nuclear - Fuel Exp.	518	DIR-P	0	0	0	0	0
Nuclear - Other Exp.	517	DIR-P	0	0	0	0	0
Nuclear - Maintenance	528-532	DIR-P	0	0	0	0	0
Nuclear Research - Misc.	524	DIR-P	0	0	0	0	0
Hydro - Operation Exp.	535-540	DIR-P	0	0	0	0	0
Hydro - Maintenance	541-545	DIR-P	0	0	0	0	0
Other Power - Fuel Exp.	547	DIR-P	0	0	0	0	0
Other Power - Other Exp.	546	DIR-P	0	0	0	0	0
Other - Maintenance Exp.	548-554	DIR-P	0	0	0	0	0
Purchased Power	555	DIR-P	0	0	0	0	0
Other Power Supply Exp.	556-557	DIR-P	0	0	0	0	0
Other Prod	Acct. No.	Funct. Code	0	0	0	0	0
Other Prod	Acct. No.	Funct. Code	0	0	0	0	0
Other Prod	Acct. No.	Funct. Code	0	0	0	0	0
Other Prod	Acct. No.	Funct. Code	0	0	0	0	0
Other Prod	Acct. No.	Funct. Code	0	0	0	0	0
Total Production Expense			0	0	0	0	0
Transmission Expense:							
Wheeling Expense	565	DIR-T	0	0	0	0	0
Trans. Exp. Operations	560-564	DIR-T	0	0	0	0	0
Trans. - Maintenance	568-574	DIR-T	0	0	0	0	0
Other Trans.	Acct. No.	Funct. Code	0	0	0	0	0
Other Trans.	Acct. No.	Funct. Code	0	0	0	0	0
Other Trans.	Acct. No.	Funct. Code	0	0	0	0	0
Total Transmission Expense			0	0	0	0	0
Distribution Expense:							
Distn. - Operations Exp.	580-589	DIR-D	0	0	0	0	0
Distn. - Maintenance Exp.	590-598	DIR-D	0	0	0	0	0
Other Dist.	Acct. No.	Funct. Code	0	0	0	0	0
Other Dist.	Acct. No.	Funct. Code	0	0	0	0	0
Total Distribution Expense			0	0	0	0	0
Customer and Sales Expenses:							
Customer Accounting Exp.	901-905	DIR-D	0	0	0	0	0
Customer Service Exp.	907-910	DIR-D	0	0	0	0	0
Sales Expense	911-916	DIR-D	0	0	0	0	0
Total Customer and Sales Expenses			0	0	0	0	0
Administration and General Expense:							
Adm. and General Salaries	920	LABOR	0	0	0	0	0
Adm. and General Salaries	920	10%LABOR	0	0	0	0	0
Office supplies & expenses	921	LABOR	0	0	0	0	0
Office supplies & expenses	921-10%	10%LABOR	0	0	0	0	0
Adm. expenses transfer- Cr.	922	LABOR	0	0	0	0	0
Adm. expenses transfer- Cr.	922-10%	10%LABOR	0	0	0	0	0
Outside services employed	923	LABOR	0	0	0	0	0
Property insurance	924	PTDG	0	0	0	0	0
Injuries and damages	925	LABOR	0	0	0	0	0
Emp. pensions & benefits	926	LABOR	0	0	0	0	0
Franchise requirements	927	DIR-D	0	0	0	0	0
Regulatory Comm. Exp.	928	DIR-D	0	0	0	0	0
Duplicate charges-credit	929	LABOR	0	0	0	0	0
General advertising Exp.	930.1	DIR-D	0	0	0	0	0
Misc. general expenses	930.2	DIR-D	0	0	0	0	0
Misc. general expenses	9.30.2-10%	10%LABOR	0	0	0	0	0
Rents	931	DIR-D	0	0	0	0	0
Maint. of general plant	932	GPM	0	0	0	0	0
Maint. of general plant	932-10%	10%LABOR	0	0	0	0	0

Other A&G	Acct. No.	Funct. Code	0	0	0	0	0
Other A&G	Acct. No.	Funct. Code	0	0	0	0	0
Total Administration and General Expenses			0	0	0	0	0
Total Operations and Maintenance			0	0	0	0	0
Schedule 3 (Report Page 2 of 2)							
Depreciation and Amortization:							
Steam - Depreciation Exp.	403	DIR-P	0	0	0	0	0
Nuclear - Depreciation Exp.	403	DIR-P	0	0	0	0	0
Hydro. - Depreciation Exp.	403	DIR-P	0	0	0	0	0
Other Prod. - Depreciation	403	DIR-P	0	0	0	0	0
Trans. - Depreciation Exp.	403	DIR-T	0	0	0	0	0
Distr. - Depreciation Exp.	403	DIR-D	0	0	0	0	0
Gen. Plant - Depreciation	403	GP	0	0	0	0	0
Other Depreciation Exp.	404	DIR-D	0	0	0	0	0
Amort Limited Term Plant	405	PTD	0	0	0	0	0
Amort. of Plant Acq.	406	PTD	0	0	0	0	0
Amort. of Prop Losses	407	PTD	0	0	0	0	0
Other Amort.	Acct. No.	Funct. Code	0	0	0	0	0
Other Amort.	Acct. No.	Funct. Code	0	0	0	0	0
Other Amort.	Acct. No.	Funct. Code	0	0	0	0	0
Total Depreciation and Amortization			0	0	0	0	0
Schedule 3A Items							
Fed Tax-Insurance Contrib.	403	LABOR	0	0	0	0	0
Fed Tax-Unemployment		LABOR	0	0	0	0	0
In-lieu Tax		Direct	0	0	0	0	0
Other Taxes		DIR-D	0	0	0	0	0
Federal Income Tax		DIR-D	0	0	0	0	0
Total Deferred Taxes		DIR-D	0	0	0	0	0
Miscellaneous Taxes		DIR-D	0	0	0	0	0
Total Non-State Taxes			0	0	0	0	0
State One (Put name here)							
State Income Taxes		DIR-D	0	0	0	0	0
State Property Tax		PTDG	0	0	0	0	0
State Unemp. Tax		LABOR	0	0	0	0	0
State Reg. Commis. Tax		DIR-D	0	0	0	0	0
State Generating Tax		DIR-D	0	0	0	0	0
State Pollution Control Tax		DIR-D	0	0	0	0	0
State Revenue and Business Tax		DIR-D	0	0	0	0	0
Local Occupation and Franchise Tax		DIR-D	0	0	0	0	0
Other Tax Item		Funct. Code	0	0	0	0	0
Other Tax Item		Funct. Code	0	0	0	0	0
Other Tax Item		Funct. Code	0	0	0	0	0
State Two (Put Name Here)							
State Income Taxes		DIR-D	0	0	0	0	0
State Property Tax		PTDG	0	0	0	0	0
State Unemp. Tax		LABOR	0	0	0	0	0
State Reg. Commis. Tax		DIR-D	0	0	0	0	0
State Generating Tax		DIR-D	0	0	0	0	0
State Pollution Control Tax		DIR-D	0	0	0	0	0
State Rev. & Business Tax		DIR-D	0	0	0	0	0
Local Occupation & Franchise		DIR-D	0	0	0	0	0
Other Tax Item		Funct. Code	0	0	0	0	0
Other Tax Item		Funct. Code	0	0	0	0	0
Other Tax Item		Funct. Code	0	0	0	0	0
Total State Taxes			0	0	0	0	0
Total Taxes			0	0	0	0	0
Schedule 3B Items							
Other Included Items:							
Gain from Disp. of Plant	411.6	PTDG	0	0	0	0	0
Loss from Disp. of Plant	411.7	PTDG	0	0	0	0	0
Total Disp. of Plant			0	0	0	0	0
Sale from Resale:							
Nonfirm Sales for Resale	447	DIR-P	0	0	0	0	0
Firm Sales For Resale	447	DIR-P	0	0	0	0	0
Total Sales from Resale			0	0	0	0	0
Other Revenues:							
Forfeited Discounts	450	DIR-D	0	0	0	0	0
Miscellaneous Service Revenues	451	DIR-P	0	0	0	0	0
Sales of water/water power	453	DIR-P	0	0	0	0	0
Rent from property	454	DIR-P	0	0	0	0	0
Interdepartmental Rents	455	DIR-P	0	0	0	0	0
Other electric revenues	456	DIR-T	0	0	0	0	0
Billing Credits		DIR-P	0	0	0	0	0
Other Revenue	Acct. No.	Funct. Code	0	0	0	0	0
Other Revenue	Acct. No.	Funct. Code	0	0	0	0	0
Total Other Revenues			0	0	0	0	0
Total Other Included Items			0	0	0	0	0
Total Operating Expenses			0	0	0	0	0

			Total	Production	Transmission	Distribution/Other	
Return from Rate Base	Schedule 1		0	0	0	0	0
Total Cost			0	0	0	0	0

Schedule 4 Items

Energy Measure - typically (MWh) or (kWh)		(kWh)
Total Load	**(kWh)**	0
Non-firm Adjustments	**(kWh)**	0
Other Adjustments	**(kWh)**	0
Distribution Losses	**(kWh)**	0
Excluded Load	**(kWh)**	0
Excl. Load Dist. Losses	**(kWh)**	0
Excluded Load Costs		0
Revenue Requirement		0
ASC Multiplier		1
Schedule 4 ASC	(mills/kWh)	**0.00**

Revenue Cap Calculation

	Last Approved
Revenue Requirement	0
Contract System Costs	0
Distribution Costs	0
Amount Exceeds Allowable Costs	0

End Schedule 4 and Data Matrix

Remainder are Necessary Calculations.

(1) Account Description	(2) Account No.(s)	(3) Funct. Method	(4) Total	(5) Production	(6) Transmission	(7) Distribution/ Other	
Labor Ratio Input:	(source - FERC From 1)						
Production	500-507	DIR-P	0	0	0	0	0
Transmission	560-573	DIR-T	0	0	0	0	0
Distribution	580-598	DIR-D	0	0	0	0	0
Customer Account	901-905	DIR-D	0	0	0	0	0
Customer Service	907-910	DIR-D	0	0	0	0	0
Sales Expense	911-916	DIR-D	0	0	0	0	0
Admin. & General	920-932	DIR-D	0	0	0	0	0
Other Labor	Acct. No.	Funct. Code	0	0	0	0	0
Other Labor	Acct. No.	Funct. Code	0	0	0	0	0
Total Labor			0	0	0	0	0

Functionalization Ratio Schedules

		Ratio Used	Total Funct.	Production	Transmission	Distribution	Math Check
GP	**Production**						
	Land and Land Rights	PTD/10% TD	0	0	0	0	0
	Structures and Improvements	PTD/10% TD	0	0	0	0	0
	Furniture and Equipment	LABOR/10% TD	0	0	0	0	0
	Transportation Equipment	TD/10% TD	0	0	0	0	0
	Stores Equipment	PTD	0	0	0	0	0
	Tools and Garage Equipment	PTD	0	0	0	0	0
	Laboratory Equipment	PTD	0	0	0	0	0
	Power Operated Equipment	TD	0	0	0	0	0
	Communication Equipment	PTD	0	0	0	0	0
	Miscellaneous Equipment	DIR-D	0	0	0	0	0
	Other Tangible Property	PTD	0	0	0	0	0
	Other Items for GP Ratio Calc.	Func. Code	0	0	0	0	0
	Other Items for GP Ratio Calc.	Func. Code	0	0	0	0	0
	Other Items for GP Ratio Calc.	Func. Code	0	0	0	0	0
	TOTAL		0	0	0	0	0
	RATIO (GP)		0.00%	0.00%	0.00%	0.00%	0
PTD	**Production, Transmission, Distribution**						
	Steam Production	DIR-P	15	5	5	5	0
	Nuclear Production	DIR-P	0	0	0	0	0
	Hydraulic Production	DIR-P	0	0	0	0	0
	Other Production	DIR-P	0	0	0	0	0
	Other Production	DIR-P	0	0	0	0	0
	Other Production	DIR-P	0	0	0	0	0
	Other Items for PTD Ratio Calc.	DIR-P	0	0	0	0	0
	Total Production Plant		15	5	5	5	0
	Transmission Plant	DIR-T	0	0	0	0	0
	Other Transmission	DIR-T	0	0	0	0	0
	Other Items for PTD Ratio Calc.	DIR-T	0	0	0	0	0
	Total Transmission Plant	DIR-T	0	0	0	0	0
	Total Distribution Plant	DIR-D	0	0	0	0	0
	TOTAL		15	5	5	5	0
	RATIO (PTD = PLANT IN SERVICE)		100.00%	33.33%	33.33%	33.33%	0
PTDG	**Production, Transmission, Distribution and General Plant**						
	PTD Total		15	5	5	5	0
	Intangible Plant	Direct	0	0	0	0	0
	Intangible Plant	PTD	0	0	0	0	0

	Other Items for PTDG Ratio Calc.	Func. Code	0	0	0	0	0
	Other Items for PTDG Ratio Calc.	Func. Code	0	0	0	0	0
	GP Total		0	0	0	0	0
	TOTAL		15	5	5	5	0
	RATIO (PTDG = GROSS PLANT)		100.00%	33.33%	33.33%	33.33%	0
TD	**Transmission, Distribution**						
	Total Transmission Plant	DIR-T	0	0	0	0	0
	Total Distribution Plant	DIR-D	0	0	0	0	0
	TOTAL		0	0	0	0	0
	RATIO (TD)		0.00%	0.00%	0.00%	0.00%	0
TDG	**Transmission, Distribution and General Plant**						
	Total Transmission Plant	DIR-T	0	0	0	0	0
	Total Distribution Plant	DIR-D	0	0	0	0	0
	Other T&D Only Items for TDG Calc.	Func. Code	0	0	0	0	0
	Other T&D Only Items for TDG Calc.	Func. Code	0	0	0	0	0
	Intangible Plant T and D Only	Direct	0	0	0	0	0
	Intangible Plant T and D Only	PTD	0	0	0	0	0
	General Plant Total 389-399(T&D Only)		0	0	0	0	0
	TOTAL		0	0	0	0	0
	RATIO (TDG)		0.00%	0.00%	0.00%	0.00%	0
GPM	**Maintenance of General Plant**						
	Structures and Improvements	PTD/10% TD	0	0	0	0	0
	Furniture and Equipment	LABOR/10% TD	0	0	0	0	0
	Communication Equipment	PTD	0	0	0	0	0
	Miscellaneous Equipment	DIR-D	0	0	0	0	0
	Other Items for GPM Calc.	Func. Code	0	0	0	0	0
	Other Items for GPM Calc.	Func. Code	0	0	0	0	0
	TOTAL		0	0	0	0	0
	RATIO (GPM)		0.00%	0.00%	0.00%	0.00%	0
LABOR	**Labor Ratios**						
	Production	DIR-P	0	0	0	0	0
	Transmission	DIR-T	0	0	0	0	0
	Distribution	DIR-D	0	0	0	0	0
	Customer Account	DIR-D	0	0	0	0	0
	Customer Service	DIR-D	0	0	0	0	0
	Sales Expense	DIR-D	0	0	0	0	0
	Admin. & General	DIR-D	0	0	0	0	0
	Other Labor	Funct. Code	0	0	0	0	0
	Other Labor	Funct. Code	0	0	0	0	0
	TOTAL		0	0	0	0	0
	RATIO (LABOR)		0.00%	0.00%	0.00%	0.00%	0

Functionalization Ratios / DataTable

************* RATIO ACRONYMS *************	
10%LABOR	10% to Production, Remainder According to Labor Ratios
10%TD	10% to Production, Remainder According to T/D Ratio
DIR-D	Direct to Distribution
DIR-P	Direct to Production
DIR-T	Direct to Transmission
DIRECT	Direct Allocation
GP	General Plant
GPM	Maintenance of General Plant
LABOR	Labor Ratios
PTD	Production, Transmission, Distribution
PTDG	Production Transmission, Distribution and General Plant
TD	Transmission, Distribution
TDG	Transmission, Distribution and General Plant

When using a functionalization code, you must use these Acronyms. Spelling is crucial, case is irrelevant.

Labor Ratios

	Totals	Production	Transmission	Distribution
Production Labor Costs	390,044	390,044		
Transmission Labor Costs	3,350		3,350	
Distribution (Operations) Labor Costs	2,973,500			2,973,500
Distribution (Maintenance) Labor Costs	1,372,929			1,372,929
Customer Accounting Labor Costs	4,723,188			4,723,188
Customer Assistance Labor Costs	51,072			51,072
Administrative & General Labor Costs	9,273,993			9,273,993
Directly Functionalized Labor Costs	18,788,076	390,044	3,350	18,394,682
Ratios	100.00%	2.08%	0.02%	97.91%

Clark Public Utilities
Rate of Return Analysis

Operating Revenues			
		Expenses	277,870,357
		Debt	30,382,261
		Rate Funded Capital	8,346,691
		Taxes	18,778,677
		Total	335,377,986
	Less:		
		Other Operating Revenue	9,099,243
			9,099,243
	Total Operating Revenues		326,278,743
Contract System Costs			
		Cost of Power	243,949,602
		Transmission Expense	-
		Distribution Expense	8,575,874
		Customer Accounting	9,060,844
		Customer Service	1,221,898
		A & G Expense	15,062,139
		Taxes	18,778,677
		Depreciation	18,274,979
		Amortization	-
	Less:		
		Other Operating Revenues	9,099,243
	Total Contract Costs		305,824,770
	Debt Service		
		Interest	12,205,944
		Principal	18,176,317
	Total		30,382,261
	Capital Expenditures from Rates		
		Transmission	768,636
		Distribution	6,381,496
		General	1,196,559
		Total	8,346,691
Case 1			
	Interest Plus Depreciation		
		Interest	12,205,944
		Depreciation	18,274,979
		Total	30,480,922
Case 2			
	Debt Service plus Capital Expenditures		
		Debt Service	30,382,261
		Capital Expenditures	8,346,691
		Total	38,728,952

Clark Public Utilities Rate of Return Calculation

Total Revenue Requirement	326,278,743
Total Operating Expense	305,824,770
Rate of Return	20,453,973

TABLE 1:
ANNUAL DEBT SERVICE REQUIREMENTS OF THE ELECTRIC SYSTEM

Year Ending 1/1	Outstanding Bonds (1)			The 2005 Bonds			
	Principal	Interest	Total	Principal	Interest	Total	Total
2006	$17,735,000	$10,869,806	$28,604,806	$0		$0	$28,604,806
2007	18,575,000	9,711,144	28,286,144	0	2,494,800	2,494,800	30,780,944
2008	19,445,000	8,841,381	28,286,381	750,000	1,733,000	2,483,000	30,769,381
2009	19,400,000	7,851,281	27,251,281	1,805,000	1,695,500	3,500,500	30,751,781
2010	20,365,000	6,874,429	27,239,429	1,895,000	1,605,250	3,500,250	30,739,679
2011	21,425,000	5,820,324	27,245,324	2,000,000	1,510,500	3,510,500	30,755,824
2012	21,335,000	4,738,944	26,073,944	2,165,000	1,410,500	3,575,500	29,649,444
2013	9,805,000	3,647,081	13,452,081	2,275,000	1,302,250	3,577,250	17,029,331
2014	9,950,000	3,201,711	13,151,711	2,390,000	1,188,500	3,578,500	16,730,211
2015	8,340,000	2,699,813	11,039,813	2,505,000	1,069,000	3,574,000	14,613,813
2016	6,230,000	2,312,968	8,542,968	2,640,000	943,750	3,583,750	12,126,718
2017	6,535,000	2,002,268	8,537,268	2,770,000	811,750	3,581,750	12,119,018
2018	6,865,000	1,674,605	8,539,605	1,220,000	673,250	1,893,250	10,432,855
2019	7,205,000	1,335,094	8,540,094	1,280,000	612,250	1,892,250	10,432,344
2020	7,565,000	977,000	8,542,000	1,345,000	548,250	1,893,250	10,435,250
2021	3,405,000	600,994	4,005,994	1,415,000	481,000	1,896,000	5,901,994
2022	3,565,000	436,331	4,001,331	1,485,000	410,250	1,895,250	5,896,581
2023	3,740,000	263,913	4,003,913	1,560,000	336,000	1,896,000	5,899,913
2024	1,705,000	80,988	1,785,988	1,635,000	258,000	1,893,000	3,678,988
2025	0	0	0	1,720,000	176,250	1,896,250	1,896,250
2026	0	0	0	1,805,000	90,250	1,895,250	1,895,250
	$213,190,000	$73,940,073	$287,130,073	$34,660,000	$19,350,300	$54,010,300	$341,140,373

(1) Excludes debt service on the Refunded Bonds.

COOKBOOK		Clark Public Utilties					
"F9" for Calculate Now					TEST PERIOD:	October 1, 2005 - September 31, 2006	
					BPA DOCKET NO.	Run No. 12 10-6-05 Base Case	
JURISDICTION:	Clark Public Utilities				LAST APPROVED FILE NUMBER	last file	
ANALYST NAME:	RDG				DATE REPORT DUE:		
					DOLLARS IN	units	
			Data Matrix				

(1) Account Description	(2) Account No.(s)	(3) Funct. Method	(4) Total	(5) Production	(6) Transmission	(7) Distribution/ Other	(8) Math Check
Schedule 1 (Report Page 1 of 2)							
Production Plant:							
Steam Production	310-316	DIR-P	0	0	0	0	0
Nuclear Production	320-325	DIR-P	0	0	0	0	0
Hydraulic Production	330-336	DIR-P	0	0	0	0	0
Other Production	340-346	DIR-P	0	0	0	0	0
Other Production	340-346	DIR-P	0	0	0	0	0
Other Production	340-346	DIR-P	0	0	0	0	0
Other Production	340-346	DIR-P	0	0	0	0	0
Total Production Plant			0	0	0	0	0
Transmission Plant:							
Transmission Plant	350-359	DIR-T	19,168,781	0	19,168,781	0	0
Other Transmission	Acct. No.	DIR-T	0	0	0	0	0
Other Transmission	Acct. No.	DIR-T	0	0	0	0	0
Total Transmission Plant	350-359		19,168,781	0	19,168,781	0	0
Total Distribution Plant	360-373	DIR-D	406,875,687	0	0	406,875,687	0
Intangible Plant	301	PTD	14,308	0	644	13,664	0
Intangible Plant	302	PTD	1,115	0	50	1,065	0
Intangible Plant	303	PTD	3,586,353	0	161,359	3,424,994	0
General Plant:	389-399						
Land and Land Rights	389	PTD	489,152	0	22,008	467,144	0
Land and Land Rights	389	10%TD	0	0	0	0	0
Structures and Improvements	390	PTD	18,389,177	0	827,374	17,561,803	0
Structures and Improvements	390	10%TD	0	0	0	0	0
Furniture and Equipment	391	LABOR	7,387,614	153,368	1,317	7,232,928	0
Furniture and Equipment	391	10%TD	0	0	0	0	0
Transportation Equipment	392	TD	8,472,587	0	381,202	8,091,385	0
Transportation Equipment	392	10%TD	0	0	0	0	0
Stores Equipment	393	PTD	313,215	0	14,092	299,123	0
Tools and Garage Equipment	394	PTD	934,984	0	42,067	892,917	0
Laboratory Equipment	395	PTD	344,589	0	15,504	329,085	0
Power Operated Equipment	396	TD	389,289	0	17,515	371,774	0
Communication Equipment	397	PTD	1,574,497	0	70,840	1,503,657	0
Miscellaneous Equipment	398	DIR-D	957,429	0	0	957,429	0
Other Tangible Property	399	PTD	10,847	0	488	10,359	0
Total General Plant	389-399		39,263,380	153,368	1,392,409	37,717,603	0
Total Electric Plant In-Service			468,909,624	153,368	20,723,243	448,033,013	0
Less - Depreciation and Amortization:							
Steam Plant	108	DIR-P		0	0	0	0
Nuclear Plant	108	DIR-P		0	0	0	0
Hydraulic Plant	108	DIR-P		0	0	0	0
Other Production Plant	108	DIR-P		0	0	0	0
Other Production Plant	108	DIR-P		0	0	0	0
Other Production Plant	108	DIR-P		0	0	0	0
Other Production Plant	108	DIR-P		0	0	0	0
Other Production Plant	108	DIR-P		0	0	0	0
Intangible Plant	108	PTD		0	0	0	0
Transmission Plant	108	DIR-T		0	0	0	0
Other Transmission Plant	108	DIR-T		0	0	0	0
Other Transmission Plant	108	DIR-T		0	0	0	0
Other Transmission Plant	108	DIR-T	0	0	0	0	0
Distribution Plant	108	DIR-D	171,591,355	0	0	171,591,355	0
General Plant	108	GP	28,335,340	110,682	1,004,865	27,219,794	0
Other Amortization	Acct. No.	Funct. Code	0	0	0	0	0
Amort. Reserve	111	PTD	3,657,068	0	164,540	3,492,528	0
Total Depreciation and Amortization			203,583,763	110,682	1,169,405	202,303,676	0
Total Net Electric Plant In-Service			265,325,861	42,686	19,553,838	245,729,337	0
Schedule 1 (Report Page 2 of 2)							
Add - Debits:							
Cash Working Capital		Input TBF Only	0	51,916	463	(52,380)	0
Plant Held Future Use	105	PTDG	0	0	0	0	0
Completed Construction	106	PTD	0	0	0	0	0
CWIP	107-120.1	DIR-D	13,821,782	0	0	13,821,782	0
Acquisitions Adjustments	114	LABOR	0	0	0	0	0
Nuclear Fuel	120.2-120.4	DIR-P	0	0	0	0	0
Investments	123	DIR-D	0	0	0	0	0
Other Investment	124	DIR-D	0	0	0	0	0
Weatherization Investment		DIR-P	301,904	301,904	0	0	0
Fuel Stock	151-152	DIR-P	0	0	0	0	0
Materials and Supplies	153-157,163	TDG	2,367,062	0	104,645	2,262,417	0

	Clearing Accounts	184	LABOR	0	0	0	0	0
	Misc. Deferred Debits	186	DIR-P	72,518,691	72,518,691	0	0	0
	Other Debits	182	DIR-D	0	0	0	0	0
	Prepayments	165	DIR-D	332,290	0	0	332,290	0
Total Debits				89,341,729	72,872,511	105,109	16,364,109	0
Less - Credits:		252-283						
	Cust. Advances for Const.	252	DIR-D	0	0	0	0	0
	Other Deferred Credits	253	DIR-D	0	0	0	0	0
	Accum Def. Inv. Tax Credit	255	DIR-D	0	0	0	0	0
	Deferred Gain - Disposition	256	PTDG	0	0	0	0	0
	Unamortized Gain - Reacq.	257	PTDG	0	0	0	0	0
	Accum. Def. Income Taxes	281-283	DIR-D	0	0	0	0	0
	Other Credits	Acct. No.	Funct. Code	0	0	0	0	0
	Other Credits	Acct. No.	Funct. Code	0	0	0	0	0
Total Credits				0	0	0	0	0
Total Rate Base				354,667,590	72,915,198	19,658,946	262,093,446	0
Rate of Return		5.77%	20,453,973					
Schedule 3 (Report Page 1 of 2)								
Production Expense:								
	Steam - Fuel Exp.	501	DIR-P	0	0	0	0	0
	Steam - Operations Exp.	500,502	DIR-P	0	0	0	0	0
	Steam - Maintenance	510-514	DIR-P	0	0	0	0	0
	Nuclear - Fuel Exp.	518	DIR-P	0	0	0	0	0
	Nuclear - Other Exp.	517	DIR-P	0	0	0	0	0
	Nuclear - Maintenance	528-532	DIR-P	0	0	0	0	0
	Nuclear Research - Misc.	524	DIR-P	0	0	0	0	0
	Hydro - Operation Exp.	535-540	DIR-P	0	0	0	0	0
	Hydro - Maintenance	541-545	DIR-P	0	0	0	0	0
	Other Power - Fuel Exp.	547	DIR-P	0	0	0	0	0
	Other Power - Other Exp.	546	DIR-P	0	0	0	0	0
	Other - Maintenance Exp.	548-554	DIR-P	0	0	0	0	0
	Purchased Power	555	DIR-P	243,949,602	243,949,602	0	0	0
	Other Power Supply Exp.	556-557	DIR-P		0	0	0	0
	Other Prod.	Acct. No.	Funct. Code	0	0	0	0	0
	Other Prod.	Acct. No.	Funct. Code	0	0	0	0	0
	Other Prod.	Acct. No.	Funct. Code	0	0	0	0	0
	Other Prod.	Acct. No.	Funct. Code	0	0	0	0	0
	Other Prod.	Acct. No.	Funct. Code	0	0	0	0	0
Total Production Expense				243,949,602	243,949,602	0	0	0
Transmission Expense:								
	Wheeling Expense	565	DIR-T	0	0	0	0	0
	Trans. Exp. Operations	560-564	DIR-T	0	0	0	0	0
	Trans. - Maintenance	568-574	DIR-T	0	0	0	0	0
	Other Trans.	Acct. No.	PTD	0	0	0	0	0
	Other Trans.	Acct. No.	PTD	0	0	0	0	0
	Other Trans.	Acct. No.	Funct. Code	0	0	0	0	0
Total Transmission Expense				0	0	0	0	0
Distribution Expense:								
	Dist. - Operations Exp.	580-589	DIR-D	4,628,128	0	0	4,628,128	0
	Dist. - Maintenance Exp.	590-598	DIR-D	3,947,746	0	0	3,947,746	0
	Other Dist.	Acct. No.	Funct. Code	0	0	0	0	0
	Other Dist.	Acct. No.	Funct. Code	0	0	0	0	0
Total Distribution Expense				8,575,874	0	0	8,575,874	0
Customer and Sales Expenses:								
	Customer Accounting Expense	901-905	DIR-D	9,060,844	0	0	9,060,844	0
	Customer Service Expense	907-910	DIR-D	1,221,898	0	0	1,221,898	0
	Sales Expense	911-916	DIR-D	0	0	0	0	0
Total Customer and Sales Expenses				10,282,742	0	0	10,282,742	0
Administration and General Expense:								
	Adm. and General Salaries	920	LABOR	8,419,521	174,791	1,501	8,243,229	0
	Adm. and General Salaries	920	10%LABOR	0	0	0	0	0
	Office supplies & expenses	921	LABOR	2,626,441	54,525	468	2,571,447	0
	Office supplies & expenses	921-10%	10%LABOR	0	0	0	0	0
	Adm. expenses transfer- Cr.	922	LABOR	(861,320)	(17,881)	(154)	(843,285)	0
	Adm. expenses transfer- Cr.	922-10%	10%LABOR	0	0	0	0	0
	Outside services employed	923	LABOR	3,291,705	68,336	587	3,222,782	0
	Property insurance	924	PTDG	23,737	8	1,049	22,680	0
	Injuries and damages	925	LABOR		0	0	0	0
	Emp. pensions & benefits	926	LABOR	260,665	5,411	46	255,207	0
	Franchise requirements	927	DIR-D		0	0	0	0
	Regulatory Comm. Exp.	928	DIR-D	0	0	0	0	0
	Duplicate charges-credit	929	LABOR	0	0	0	0	0
	General advertising Exp.	930.1	DIR-D	0	0	0	0	0
	Misc. general expenses	930.2	DIR-D	0	0	0	0	0
	Misc. general expenses	9.30.2-10%	10%LABOR	1,301,390	130,139	209	1,171,042	0
	Rents	931	DIR-D	0	0	0	0	0
	Maint. of general plant	932	GPM	0	0	0	0	0
	Maint. of general plant	932-10%	10%LABOR	0	0	0	0	0
	Other A&G	Acct. No.	Funct. Code	0	0	0	0	0
	Other A&G	Acct. No.	Funct. Code	0	0	0	0	0
Total Administration and General Expenses				15,062,139	415,330	3,708	14,643,102	0
Total Operations and Maintenance				277,870,357	244,364,932	3,708	33,501,718	0

Schedule 3 (Report Page 2 of 2)							
Depreciation and Amortization:							
Steam - Depreciation Exp.	403	DIR-P	0	0	0	0	0
Nuclear - Depreciation Exp.	403	DIR-P	0	0	0	0	0
Hydro. - Depreciation Exp.	403	DIR-P	0	0	0	0	0
Other Prod. - Depreciation	403	DIR-P	0	0	0	0	0
Trans. - Depreciation Exp.	403	DIR-T	0	0	0	0	0
Distr. - Depreciation Exp.	403	DIR-D	18,274,979	0	0	18,274,979	0
Gen. Plant - Depreciation	403	GP	0	0	0	0	0
Other Depreciation Exp.	404	DIR-D	0	0	0	0	0
Amort. Limited Term Plant	405	PTD	0	0	0	0	0
Amort. of Plant Acq.	406	PTD	0	0	0	0	0
Amort. of Prop. Losses	407	PTD	0	0	0	0	0
Other Amort.	Acct. No.	PTDG	0	0	0	0	0
Other Amort.	Acct. No.	Funct. Code	0	0	0	0	0
Other Amort.	Acct. No.	Funct. Code	0	0	0	0	0
Total Depreciation and Amortization			18,274,979	0	0	18,274,979	0
Schedule 3A Items							
Fed Tax-Insurance Contrib.	403	LABOR	0	0	0	0	0
Fed Tax-Unemployment		LABOR	0	0	0	0	0
In-lieu Tax		Calculated Below	18,778,677	14,910,021	68,897	3,799,759	0
Other Taxes		DIR-D	0	0	0	0	0
Federal Income Tax		DIR-D	0	0	0	0	0
Total Deferred Taxes		DIR-D	0	0	0	0	0
Miscellaneous Taxes		DIR-D	0	0	0	0	0
Total Non-State Taxes			18,778,677	14,910,021	68,897	3,799,759	0
Washington							
State Income Taxes		DIR-D	0	0	0	0	0
State Property Tax		PTDG	0	0	0	0	0
State Unemp. Tax		LABOR	0	0	0	0	0
State Reg. Commis. Tax		DIR-D	0	0	0	0	0
State Generating Tax		DIR-D	0	0	0	0	0
State Pollution Control Tax		DIR-D	0	0	0	0	0
State Revenue and Business Tax		DIR-D	0	0	0	0	0
Local Occupation and Franchise Tax		DIR-D	0	0	0	0	0
Misc Taxes		PTDG	0	0	0	0	0
Other Tax Item		Funct. Code	0	0	0	0	0
Other Tax Item		Funct. Code	0	0	0	0	0
State Two (Put Name Here)							
State Income Taxes		DIR-D	0	0	0	0	0
State Property Tax		PTDG	0	0	0	0	0
State Unemp. Tax		LABOR	0	0	0	0	0
State Reg. Commis. Tax		DIR-D	0	0	0	0	0
State Generating Tax		DIR-D	0	0	0	0	0
State Pollution Control Tax		DIR-D	0	0	0	0	0
State Rev. & Business Tax		DIR-D	0	0	0	0	0
Local Occupation & Franchise		DIR-D	0	0	0	0	0
Other Tax Item		Funct. Code	0	0	0	0	0
Other Tax Item		Funct. Code	0	0	0	0	0
Other Tax Item		Funct. Code	0	0	0	0	0
Total State Taxes			0	0	0	0	0
Total Taxes			18,778,677	14,910,021	68,897	3,799,759	0
Schedule 3B Items							
Other Included Items:							
Gain from Disp. of Plant	411.6	PTDG	0	0	0	0	0
Loss from Disp. of Plant	411.7	PTDG	0	0	0	0	0
Total Disp. of Plant			0	0	0	0	0
Sale from Resale:							
Nonfirm Sales for Resale	447	DIR-P	0	0	0	0	0
Firm Sales For Resale	447	DIR-P	0	0	0	0	0
Total Sales from Resale			0	0	0	0	0
Other Revenues:							
Forfeited Discounts	450	DIR-P	0	0	0	0	0
Miscellaneous Service Revenues	451	DIR-D	7,768,165	0	0	7,768,165	0
Sales of water/water power	453	DIR-P	0	0	0	0	0
Rent from property	454	DIR-P	0	0	0	0	0
Interdepartmental Rents	455	DIR-P	0	0	0	0	0
Other electric revenues	456	DIR-T	0	0	0	0	0
Billing Credits		DIR-P	0	0	0	0	0
Other Revenue	Acct. No.	DIR-D	776,928	0	0	776,928	0
Other Revenue	Acct. No.	DIR-D	554,150	0	0	554,150	0
Total Other Revenues			9,099,243	0	0	9,099,243	0
Total Other Included Items			9,099,243	0	0	9,099,243	0
Total Operating Expenses			305,824,770	259,274,953	72,604	46,477,212	0
Return from Rate Base	Schedule 1		20,453,973	4,205,080	1,133,748	15,115,146	0
Total Cost			326,278,743	263,480,033	1,206,352	61,592,358	0
Schedule 4 Items							
Energy Measure - either (MWh) or (kWh)		(kWh)					
Total Load	(kWh)	4,647,967,387					
Non-firm Adjustments	(kWh)	0		MWh input voltage		4,647,967,387	

Other Adjustments	(kWh)	0			
Distribution Losses	(kWh)		MWh Sales Forecast		4,486,381,461
Excluded Load	(kWh)	0			
Excl. Load Dist. Losses	(kWh)	161,585,926	Distribution Losses		161,585,926
Excluded Load Costs		0			
Revenue Requirement		326,278,743			
ASC Multiplier		1,000			
Schedule 4 ASC	(mills/kWh)	**58.9977**			

End Schedule 4 and Data Matrix

Remainder are Necessary Calculations.

(1) Account Description	(2) Account No.(s)	(3) Funct. Method	(4) Total	(5) Production	(6) Transmission	(7) Distribution/ Other	
Labor Ratio Input:	(source - FERC From 1)						
Production	500-507	DIR-P	390,044	390,044	0	0	0
Transmission	560-573	DIR-T	3,350	0	3,350	0	0
Distribution	580-598	DIR-D	4,346,429	0	0	4,346,429	0
Customer Account	901-905	DIR-D	4,723,188	0	0	4,723,188	0
Customer Service	907-910	DIR-D	51,072	0	0	51,072	0
Sales Expense	911-916	DIR-D	0	0	0	0	0
Admin. & General	920-932	DIR-D	9,273,993	0	0	9,273,993	0
Other Labor	Acct. No.	Funct. Code	0	0	0	0	0
Other Labor	Acct. No.	Funct. Code	0	0	0	0	0
Total Labor			18,788,076	390,044	3,350	18,394,682	0
Cash Working Capital Calculation:							
Total Production O&M			243,949,602	243,949,602	0	0	
Total Transmission O&M			0	0	0	0	
Total Distribution O&M			8,575,874	0	0	8,575,874	
Total Customer and Sales O&M			10,282,742	0	0	10,282,742	
Total Administrative and General O&M			15,062,139	415,330	3,708	14,643,102	
Less Purchased Power and Fuel Costs			(243,949,602)	(243,949,602)	0	0	
Total O&M Expenses (Less Purch. Power and Fuel Costs)			33,920,755	415,330	3,708	33,501,718	
One Eighth O&M Expenses (Less Purch. Power and Fuel Costs)			4,240,094	51,916	463	4,187,715	
Allowable Functionalized Cash Working Capital			4,240,094	51,916	463	4,187,715	
In-lieu Tax Caluculation:	***For private utilities. You must input high and low tax rates.***						
Net Plant Amounts (from "As Filed" Data Matrix)			261,739,508	42,686	19,392,479	242,304,343	
Tax Rates	Low	High					
	0.0%	0.0%					
In-lieu Tax (from "As Filed" Data Matrix)			18,778,677	14,910,021	68,897	3,799,759	
In Lieu Tax Cap (calculated)			0				
Lessor of In Lieu Tax and In Lieu Tax Cap			0				
				Low Rate	Low Rate	High Rate	
Direct Analysis: (Net Plant * Applicable Tax Rate)			Total	0.0%	0.0%	0.0%	
			0	0	0	0	
Percentage Calculation			0.0%	0.0%	0.0%	0.0%	
Functionalized In Lieu Tax			18,778,677	14,910,021	68,897	3,799,759	
referenced to "Cookbook" In Lieu Tax above							

Functionalization Ratio Schedules

		Ratio Used	Total Funct.	Production	Transmission	Distribution	Math Check
GP	**Production**						
	Land and Land Rights	PTD/10% TD	489,152	0	22,008	467,144	0
	Structures and Improvements	PTD/10% TD	18,389,177	0	827,374	17,561,803	0
	Furniture and Equipment	LABOR/10% TD	7,387,614	153,368	1,317	7,232,928	0
	Transportation Equipment	TD/10% TD	8,472,587	0	381,202	8,091,385	0
	Stores Equipment	PTD	313,215	0	14,092	299,123	0
	Tools and Garage Equipment	PTD	934,984	0	42,067	892,917	0
	Laboratory Equipment	PTD	344,589	0	15,504	329,085	0
	Power Operated Equipment	TD	389,289	0	17,515	371,774	0
	Communication Equipment	PTD	1,574,497	0	70,840	1,503,657	0
	Miscellaneous Equipment	DIR-D	957,429	0	0	957,429	0
	Other Tangible Property	PTD	10,847	0	488	10,359	0
	Other Items for GP Ratio Calc.	Func. Code	0	0	0	0	0
	Other Items for GP Ratio Calc.	Func. Code	0	0	0	0	0
	Other Items for GP Ratio Calc.	Func. Code	0	0	0	0	0
	TOTAL		39,263,380	153,368	1,392,409	37,717,603	0
	RATIO (GP)		100.00%	0.39%	3.55%	96.06%	0
PTD	**Production, Transmission, Distribution**						
	Steam Production	DIR-P	0	0	0	0	0
	Nuclear Production	DIR-P	0	0	0	0	0
	Hydraulic Production	DIR-P	0	0	0	0	0
	Other Production	DIR-P	0	0	0	0	0
	Other Production	DIR-P	0	0	0	0	0
	Other Production	DIR-P	0	0	0	0	0
	Other Items for PTD Ratio Calc.	DIR-P	0	0	0	0	0
	Total Production Plant		0	0	0	0	0

	Transmission Plant	DIR-T	19,168,781	0	19,168,781	0	0
	Other Transmission	DIR-T	0	0	0	0	0
	Other Items for PTD Ratio Calc.	DIR-T	0	0	0	0	0
	Total Transmission Plant	DIR-T	19,168,781	0	19,168,781	0	0
	Total Distribution Plant	DIR-D	406,875,687	0	0	406,875,687	0
	TOTAL		426,044,468	0	19,168,781	406,875,687	0
	RATIO (PTD = PLANT IN SERVICE)		100.00%	0.00%	4.50%	95.50%	0
PTDG	**Production, Transmission, Distribution and General Plant**						
	PTD Total		426,044,468	0	19,168,781	406,875,687	0
	Intangible Plant	PTD	14,308	0	644	13,664	0
	Intangible Plant	PTD	1,115	0	50	1,065	0
	Intangible Plant	PTD	3,586,353	0	161,359	3,424,994	0
	Other Items for PTDG Ratio Calc.	Func. Code	0	0	0	0	0
	GP Total		39,263,380	153,368	1,392,409	37,717,603	0
	TOTAL		468,909,624	153,368	20,723,243	448,033,013	0
	RATIO (PTDG = GROSS PLANT)		100.00%	0.03%	4.42%	95.55%	0
TD	**Transmission, Distribution**						
	Total Transmission Plant	DIR-T	19,168,781	0	19,168,781	0	0
	Total Distribution Plant	DIR-D	406,875,687	0	0	406,875,687	0
	TOTAL		426,044,468	0	19,168,781	406,875,687	0
	RATIO (TD)		100.00%	0.00%	4.50%	95.50%	0
TDG	**Transmission, Distribution and General Plant**						
	Total Transmission Plant	DIR-T	19,168,781	0	19,168,781	0	0
	Total Distribution Plant	DIR-D	406,875,687	0	0	406,875,687	0
	Other T&D Only Items for TDG Calc.	Func. Code	0	0	0	0	0
	Intangible Plant T and D Only	PTD	14,308	0	644	13,664	0
	Intangible Plant T and D Only	PTD	1,115	0	50	1,065	0
	Intangible Plant T and D Only	PTD	3,586,353	0	161,359	3,424,994	0
	General Plant Total 389-399(T&D Only)		39,110,012	0	1,392,409	37,717,603	0
	TOTAL		468,756,256	0	20,723,243	448,033,013	0
	RATIO (TDG)		100.00%	0.00%	4.42%	95.58%	0
GPM	**Maintenance of General Plant**						
	Structures and Improvements	PTD/10% TD	18,389,177	0	827,374	17,561,803	0
	Furniture and Equipment	LABOR/10% TD	7,387,614	153,368	1,317	7,232,928	0
	Communication Equipment	PTD	1,574,497	0	70,840	1,503,657	0
	Miscellaneous Equipment	DIR-D	957,429	0	0	957,429	0
	Other Items for GPM Calc.	Func. Code	0	0	0	0	0
	Other Items for GPM Calc.	Func. Code	0	0	0	0	0
	TOTAL		28,308,717	153,368	899,532	27,255,817	0
	RATIO (GPM)		100.00%	0.54%	3.18%	96.28%	0
LABOR	**Labor Ratios**						
	Production	DIR-P	390,044	390,044	0	0	0
	Transmission	DIR-T	3,350	0	3,350	0	0
	Distribution	DIR-D	4,346,429	0	0	4,346,429	0
	Customer Account	DIR-D	4,723,188	0	0	4,723,188	0
	Customer Service	DIR-D	51,072	0	0	51,072	0
	Sales Expense	DIR-D	0	0	0	0	0
	Admin. & General	DIR-D	9,273,993	0	0	9,273,993	0
	Other Labor	Funct. Code	0	0	0	0	0
	Other Labor	Funct. Code	0	0	0	0	0
	TOTAL		18,788,076	390,044	3,350	18,394,682	0
	RATIO (LABOR)		100.00%	2.08%	0.02%	97.91%	0

Functionalization Ratios / DataTable

10%LABOR	**10.00%**	**0.02%**	**89.98%**
10%TD	**10.00%**	**4.05%**	**85.95%**
DIR-D	**0.00%**	**0.00%**	**100.00%**
DIR-P	**100.00%**	**0.00%**	**0.00%**
DIR-T	**0.00%**	**100.00%**	**0.00%**
DIRECT	**0.00%**	**0.00%**	**0.00%**
GP	**0.39%**	**3.55%**	**96.06%**
GPM	**0.54%**	**3.18%**	**96.28%**
LABOR	**2.08%**	**0.02%**	**97.91%**
PTD	**0.00%**	**4.50%**	**95.50%**
PTDG	**0.03%**	**4.42%**	**95.55%**
TD	**0.00%**	**4.50%**	**95.50%**
TDG	**0.00%**	**4.42%**	**95.58%**

************ RATIO ACRONYMS ************	
10%LABOR	10% to Production, Remainder According to Labor Ratios
10%TD	10% to Production, Remainder According to T/D Ratio
DIR-D	Direct to Distribution
DIR-P	Direct to Production
DIR-T	Direct to Transmission
DIRECT	Direct Allocation
GP	General Plant
GPM	Maintenance of General Plant
LABOR	Labor Ratios
PTD	Production, Transmission, Distribution
PTDG	Production Transmission, Distribution and General Plant
TD	Transmission, Distribution
TDG	Transmission, Distribution and General Plant

When using a functionalization code, you must use these Acronyms. Spelling is crucial, case is irrelevant.

AS FILED Clark Public Utilties

TEST PERIOD: October 1, 2005 - September 31, 2006
BPA DOCKET NO. Run No. 12 10-6-05 Base Case
JURISDICTION: Clark Public Utilities
LAST APPROVED FILE NUMBER last file
ANALYST NAME: RDG
DATE REPORT DUE: 0
DOLLARS IN units

Data Matrix

(1) Account Description	(2) Account No.(s)	(3) Funct. Method	(4) Total	(5) Production	(6) Transmission	(7) Distribution/ Other	(8) Math Check
Schedule 1 (Report Page 1 of 2)							
Production Plant:							
Steam Production	310-316	DIR-P	0	0	0	0	0
Nuclear Production	320-325	DIR-P	0	0	0	0	0
Hydraulic Production	330-336	DIR-P	0	0	0	0	0
Other Production	340-346	DIR-P	0	0	0	0	0
Other Production	340-346	DIR-P	0	0	0	0	0
Other Production	340-346	DIR-P	0	0	0	0	0
Other Production	340-346	DIR-P	0	0	0	0	0
Total Production Plant			0	0	0	0	0
Transmission Plant:							
Transmission Plant	350-359	DIR-T	19,168,781	0	19,168,781	0	0
Other Transmission	Acct. No.	DIR-T	0	0	0	0	0
Other Transmission	Acct. No.	DIR-T	0	0	0	0	0
Total Transmission Plant	350-359		19,168,781	0	19,168,781	0	0
Total Distribution Plant	360-373	DIR-D	406,875,687	0	0	406,875,687	0
Intangible Plant	301	PTD	14,308	0	644	13,664	0
Intangible Plant	302	PTD	1,115	0	50	1,065	0
Intangible Plant	303	PTD	3,586,353	0	161,359	3,424,994	0
General Plant:	389-399						
Land and Land Rights	389	PTD	489,152	0	22,008	467,144	0
Land and Land Rights	389	10%TD	0	0	0	0	0
Structures and Improvements	390	PTD	18,389,177	0	827,374	17,561,803	0
Structures and Improvements	390	10%TD	0	0	0	0	0
Furniture and Equipment	391	LABOR	7,387,614	153,368	1,317	7,232,928	0
Furniture and Equipment	391	10%TD	0	0	0	0	0
Transportation Equipment	392	TD	8,472,587	0	381,202	8,091,385	0
Transportation Equipment	392	10%TD	0	0	0	0	0
Stores Equipment	393	PTD	313,215	0	14,092	299,123	0
Tools and Garage Equipment	394	PTD	934,984	0	42,067	892,917	0
Laboratory Equipment	395	PTD	344,589	0	15,504	329,085	0
Power Operated Equipment	396	TD	389,289	0	17,515	371,774	0
Communication Equipment	397	PTD	1,574,497	0	70,840	1,503,657	0
Miscellaneous Equipment	398	DIR-D	957,429	0	0	957,429	0
Other Tangible Property	399	PTD	10,847	0	488	10,359	0
Total General Plant	389-399		39,263,380	153,368	1,392,409	37,717,603	0
Total Electric Plant In-Service			465,323,271	153,368	20,561,884	444,608,019	0
Less - Depreciation and Amortization:							
Steam Plant	108	DIR-P	0	0	0	0	0
Nuclear Plant	108	DIR-P	0	0	0	0	0
Hydraulic Plant	108	DIR-P	0	0	0	0	0
Other Production Plant	108	DIR-P	0	0	0	0	0
Other Production Plant	108	DIR-P	0	0	0	0	0
Other Production Plant	108	DIR-P	0	0	0	0	0
Other Production Plant	108	DIR-P	0	0	0	0	0
Other Production Plant	108	DIR-P	0	0	0	0	0
Intangible Plant	108	PTD	0	0	0	0	0
Transmission Plant	108	DIR-T	0	0	0	0	0
Other Transmission Plant	108	DIR-T	0	0	0	0	0
Other Transmission Plant	108	DIR-T	0	0	0	0	0
Other Transmission Plant	108	DIR-T	0	0	0	0	0
Distribution Plant	108	DIR-D	171,591,355	0	0	171,591,355	0
General Plant	108	GP	28,335,340	110,682	1,004,865	27,219,794	0
Other Amortization	Acct. No.	Funct. Code	0	0	0	0	0
Amort. Reserve	111	PTD	3,657,068	0	164,540	3,492,528	0
Total Depreciation and Amortization			203,583,763	110,682	1,169,405	202,303,676	0
Total Net Electric Plant In-Service			261,739,508	42,686	19,392,479	242,304,343	0
Schedule 1 (Report Page 2 of 2)							
Add - Debits:							
Cash Working Capital		Direct	0	51,916	463	(52,380)	0
Plant Held Future Use	105	PTDG	0	0	0	0	0
Completed Construction	106	PTD	0	0	0	0	0
CWIP	107-120.1	DIR-D	13,821,782	0	0	13,821,782	0
Acquisitions Adjustments	114	LABOR	0	0	0	0	0
Nuclear Fuel	120.2-120.4	DIR-P	0	0	0	0	0
Investments	123	DIR-D	0	0	0	0	0
Other Investment	124	DIR-D	0	0	0	0	0

	Weatherization Investment	0	DIR-P	301,904	301,904	0	0	0
	Fuel Stock	151-152	DIR-P	0	0	0	0	0
	Materials and Supplies	153-157,163	TDG	2,367,062	0	104,645	2,262,417	0
	Clearing Accounts	184	LABOR	0	0	0	0	0
	Misc. Deferred Debits	186	DIR-P	72,518,691	72,518,691	0	0	0
	Other Debits	182	DIR-D	0	0	0	0	0
	Prepayments	165	DIR-D	332,290	0	0	332,290	0
Total Debits				89,341,729	72,872,511	105,109	16,364,109	0
Less - Credits:		252-283						
	Cust. Advances for Const.	252	DIR-D	0	0	0	0	0
	Other Deferred Credits	253	DIR-D	0	0	0	0	0
	Accum Def. Inv. Tax Credit	255	DIR-D	0	0	0	0	0
	Deferred Gain - Disposition	256	PTDG	0	0	0	0	0
	Unamortized Gain - Reacq.	257	PTDG	0	0	0	0	0
	Accum. Def. Income Taxes	281-283	DIR-D	0	0	0	0	0
	Other Credits	Acct. No.	Funct. Code	0	0	0	0	0
	Other Credits	Acct. No.	Funct. Code	0	0	0	0	0
Total Credits				0	0	0	0	0
Total Rate Base				351,081,237	72,915,198	19,497,588	258,668,452	0
Rate of Return		5.77%						
Schedule 3 (Report Page 1 of 2)								
Production Expense:								
	Steam - Fuel Exp.	501	DIR-P	0	0	0	0	0
	Steam - Operations Exp.	500,502	DIR-P	0	0	0	0	0
	Steam - Maintenance	510-514	DIR-P	0	0	0	0	0
	Nuclear - Fuel Exp.	518	DIR-P	0	0	0	0	0
	Nuclear - Other Exp.	517	DIR-P	0	0	0	0	0
	Nuclear - Maintenance	528-532	DIR-P	0	0	0	0	0
	Nuclear Research - Misc.	524	DIR-P	0	0	0	0	0
	Hydro - Operation Exp.	535-540	DIR-P	0	0	0	0	0
	Hydro - Maintenance	541-545	DIR-P	0	0	0	0	0
	Other Power - Fuel Exp.	547	DIR-P	0	0	0	0	0
	Other Power - Other Exp.	546	DIR-P	0	0	0	0	0
	Other - Maintenance Exp.	548-554	DIR-P	0	0	0	0	0
	Purchased Power	555	DIR-P	243,949,602	243,949,602	0	0	0
	Other Power Supply Exp.	556-557	DIR-P	0	0	0	0	0
	Other Prod.	Acct. No.	Funct. Code	0	0	0	0	0
	Other Prod.	Acct. No.	Funct. Code	0	0	0	0	0
	Other Prod.	Acct. No.	Funct. Code	0	0	0	0	0
	Other Prod.	Acct. No.	Funct. Code	0	0	0	0	0
	Other Prod.	Acct. No.	Funct. Code	0	0	0	0	0
Total Production Expense				243,949,602	243,949,602	0	0	0
Transmission Expense:								
	Wheeling Expense	565	DIR-T	0	0	0	0	0
	Trans. Exp. Operations	560-564	DIR-T	0	0	0	0	0
	Trans. - Maintenance	568-574	DIR-T	0	0	0	0	0
	Other Trans.	Acct. No.	PTD	0	0	0	0	0
	Other Trans.	Acct. No.	PTD	0	0	0	0	0
	Other Trans.	Acct. No.	Funct. Code	0	0	0	0	0
Total Transmission Expense				0	0	0	0	0
Distribution Expense:								
	Dist. - Operations Exp.	580-589	DIR-D	4,628,128	0	0	4,628,128	0
	Dist. - Maintenance Exp.	590-598	DIR-D	3,947,746	0	0	3,947,746	0
	Other Dist.	Acct. No.	Funct. Code	0	0	0	0	0
	Other Dist.	Acct. No.	Funct. Code	0	0	0	0	0
Total Distribution Expense				8,575,874	0	0	8,575,874	0
Customer and Sales Expenses:								
	Customer Accounting Expense	901-905	DIR-D	9,060,844	0	0	9,060,844	0
	Customer Service Expense	907-910	DIR-D	1,221,898	0	0	1,221,898	0
	Sales Expense	911-916	DIR-D	0	0	0	0	0
Total Customer and Sales Expenses				10,282,742	0	0	10,282,742	0
Administration and General Expense:								
	Adm. and General Salaries	920	LABOR	8,419,521	174,791	1,501	8,243,229	0
	Adm. and General Salaries	920	10%LABOR	0	0	0	0	0
	Office supplies & expenses	921	LABOR	2,626,441	54,525	468	2,571,447	0
	Office supplies & expenses	921-10%	10%LABOR	0	0	0	0	0
	Adm. expenses transfer- Cr.	922	LABOR	(861,320)	(17,881)	(154)	(843,285)	0
	Adm. expenses transfer- Cr.	922-10%	10%LABOR	0	0	0	0	0
	Outside services employed	923	LABOR	3,291,705	68,336	587	3,222,782	0
	Property insurance	924	PTDG	23,737	8	1,049	22,680	0
	Injuries and damages	925	LABOR	0	0	0	0	0
	Emp. pensions & benefits	926	LABOR	260,665	5,411	46	255,207	0
	Franchise requirements	927	DIR-D	0	0	0	0	0
	Regulatory Comm. Exp.	928	DIR-D	0	0	0	0	0
	Duplicate charges-credit	929	LABOR	0	0	0	0	0
	General advertising Exp.	930.1	DIR-D	0	0	0	0	0
	Misc. general expenses	930.2	DIR-D	0	0	0	0	0
	Misc. general expenses	9.30.2-10%	10%LABOR	1,301,390	130,139	209	1,171,042	0
	Rents	931	DIR-D	0	0	0	0	0
	Maint. of general plant	932	GPM	0	0	0	0	0
	Maint. of general plant	932-10%	10%LABOR	0	0	0	0	0

Other A&G	Acct. No.	Funct. Code	0	0	0	0	0
Other A&G	Acct. No.	Funct. Code	0	0	0	0	0
Total Administration and General Expenses			15,062,139	415,330	3,708	14,643,102	0
Total Operations and Maintenance			277,870,357	244,364,932	3,708	33,501,718	0
Schedule 3 (Report Page 2 of 2)							
Depreciation and Amortization:							
Steam - Depreciation Exp.	403	DIR-P	0	0	0	0	0
Nuclear - Depreciation Exp.	403	DIR-P	0	0	0	0	0
Hydro. - Depreciation Exp.	403	DIR-P	0	0	0	0	0
Other Prod. - Depreciation	403	DIR-P	0	0	0	0	0
Trans. - Depreciation Exp.	403	DIR-T	0	0	0	0	0
Distr. - Depreciation Exp.	403	DIR-D	18,274,979	0	0	18,274,979	0
Gen. Plant - Depreciation	403	GP	0	0	0	0	0
Other Depreciation Exp.	404	DIR-D	0	0	0	0	0
Amort. Limited Term Plant	405	PTD	0	0	0	0	0
Amort. of Plant Acq.	406	PTD	0	0	0	0	0
Amort. of Prop. Losses	407	PTD	0	0	0	0	0
Other Amort.	Acct. No.	PTDG	0	0	0	0	0
Other Amort.	Acct. No.	Funct. Code	0	0	0	0	0
Other Amort.	Acct. No.	Funct. Code	0	0	0	0	0
Total Depreciation and Amortization			18,274,979	0	0	18,274,979	0
Schedule 3A Items							
Fed Tax-Insurance Contrib.	403	LABOR	0	0	0	0	0
Fed Tax-Unemployment		LABOR	0	0	0	0	0
In-lieu Tax		Direct	18,778,677	14,910,021.11	68,896.61	3,799,759.28	0
Other Taxes		DIR-D	0	0	0	0	0
Federal Income Tax		DIR-D	0	0	0	0	0
Total Deferred Taxes		DIR-D	0	0	0	0	0
Miscellaneous Taxes		DIR-D	0	0	0	0	0
Total Non-State Taxes			18,778,677	14,910,021	68,897	3,799,759	0
Washington							
State Income Taxes		DIR-D	0	0	0	0	0
State Property Tax		PTDG	0	0	0	0	0
State Unemp. Tax		LABOR	0	0	0	0	0
State Reg. Commis. Tax		DIR-D	0	0	0	0	0
State Generating Tax		DIR-D	0	0	0	0	0
State Pollution Control Tax		DIR-D	0	0	0	0	0
State Revenue and Business Tax		DIR-D	0	0	0	0	0
Local Occupation and Franchise Tax		DIR-D	0	0	0	0	0
Misc Taxes		PTDG	0	0	0	0	0
Other Tax Item		Funct. Code	0	0	0	0	0
Other Tax Item		Funct. Code	0	0	0	0	0
State Two (Put Name Here)							
State Income Taxes		DIR-D	0	0	0	0	0
State Property Tax		PTDG	0	0	0	0	0
State Unemp. Tax		LABOR	0	0	0	0	0
State Reg. Commis. Tax		DIR-D	0	0	0	0	0
State Generating Tax		DIR-D	0	0	0	0	0
State Pollution Control Tax		DIR-D	0	0	0	0	0
State Rev. & Business Tax		DIR-D	0	0	0	0	0
Local Occupation & Franchise		DIR-D	0	0	0	0	0
Other Tax Item		Funct. Code	0	0	0	0	0
Other Tax Item		Funct. Code	0	0	0	0	0
Other Tax Item		Funct. Code	0	0	0	0	0
Total State Taxes			0	0	0	0	0
Total Taxes			18,778,677	14,910,021	68,897	3,799,759	0
Schedule 3B Items							
Other Included Items:							
Gain from Disp. of Plant	411.6	PTDG	0	0	0	0	0
Loss from Disp. of Plant	411.7	PTDG	0	0	0	0	0
Total Disp. of Plant			0	0	0	0	0
Sale from Resale:							
Nonfirm Sales for Resale	447	DIR-P	0	0	0	0	0
Firm Sales For Resale	447	DIR-P	0	0	0	0	0
Total Sales from Resale			0	0	0	0	0
Other Revenues:							
Forfeited Discounts	450	DIR-P	0	0	0	0	0
Miscellaneous Service Revenues	451	DIR-D	7,768,165	0	0	7,768,165	0
Sales of water/water power	453	DIR-P	0	0	0	0	0
Rent from property	454	DIR-P	0	0	0	0	0
Interdepartmental Rents	455	DIR-P	0	0	0	0	0
Other electric revenues	456	DIR-T	0	0	0	0	0
Billing Credits		DIR-P	0	0	0	0	0
Other Revenue	Acct. No.	DIR-D	776,928	0	0	776,928	0
Other Revenue	Acct. No.	DIR-D	554,150	0	0	554,150	0
Total Other Revenues			9,099,243	0	0	9,099,243	0
Total Other Included Items			9,099,243	0	0	9,099,243	0
Total Operating Expenses			305,824,770	259,274,953	72,604	46,477,212	0

Return from Rate Base	Schedule 1		20,247,145	4,205,080	1,124,442	14,917,624	0
Total Cost			326,071,915	263,480,033	1,197,046	61,394,836	0
			100%	81%	0%	19%	

Schedule 4 Items

Energy Measure - either (MWh) or (kWh)		(kWh)
Total Load	**(kWh)**	4,647,967,387
Non-firm Adjustments	**(kWh)**	0
Other Adjustments	**(kWh)**	0
Distribution Losses	**(kWh)**	0
Excluded Load	**(kWh)**	0
Excl. Load Dist. Losses	**(kWh)**	161,585,926
Excluded Load Costs		0
Revenue Requirement		300,378,529
ASC Multiplier		1,000
Schedule 4 ASC	(mills/kWh)	58.9957

Revenue Cap Calculation

	As Filed
Revenue Requirement	300,378,529
Contract System Costs	264,677,079
Distribution Costs	61,394,836
Amount Exceeds Allowable Costs	25,693,386

End Schedule 4 and Data Matrix

Remainder are Necessary Calculations.

(1) Account Description	(2) Account No.(s)	(3) Funct. Method	(4) Total	(5) Production	(6) Transmission	(7) Distribution/ Other	
Labor Ratio Input:	(source - FERC From 1)						
Production	500-507	DIR-P	390,044	390,044	0	0	0
Transmission	560-573	DIR-T	3,350	0	3,350	0	0
Distribution	580-598	DIR-D	4,346,429	0	0	4,346,429	0
Customer Account	901-905	DIR-D	4,723,188	0	0	4,723,188	0
Customer Service	907-910	DIR-D	51,072	0	0	51,072	0
Sales Expense	911-916	DIR-D	0	0	0	0	0
Admin. & General	920-932	DIR-D	9,273,993	0	0	9,273,993	0
Other Labor	Acct. No.	Funct. Code	0	0	0	0	0
Other Labor	Acct. No.	Funct. Code	0	0	0	0	0
Total Labor			18,788,076	390,044	3,350	18,394,682	0

Functionalization Ratio Schedules

		Ratio Used	Total Funct.	Production	Transmission	Distribution	Math Check
GP	**Production**						
	Land and Land Rights	PTD/10% TD	489,152	0	22,008	467,144	0
	Structures and Improvements	PTD/10% TD	18,389,177	0	827,374	17,561,803	0
	Furniture and Equipment	LABOR/10% TD	7,387,614	153,368	1,317	7,232,928	0
	Transportation Equipment	TD/10% TD	8,472,587	0	381,202	8,091,385	0
	Stores Equipment	PTD	313,215	0	14,092	299,123	0
	Tools and Garage Equipment	PTD	934,984	0	42,067	892,917	0
	Laboratory Equipment	PTD	344,589	0	15,504	329,085	0
	Power Operated Equipment	TD	389,289	0	17,515	371,774	0
	Communication Equipment	PTD	1,574,497	0	70,840	1,503,657	0
	Miscellaneous Equipment	DIR-D	957,429	0	0	957,429	0
	Other Tangible Property	PTD	10,847	0	488	10,359	0
	Other Items for GP Ratio Calc.	Func. Code	0	0	0	0	0
	Other Items for GP Ratio Calc.	Func. Code	0	0	0	0	0
	Other Items for GP Ratio Calc.	Func. Code	0	0	0	0	0
	TOTAL		39,263,380	153,368	1,392,409	37,717,603	0
	RATIO (GP)		100.00%	0.39%	3.55%	96.06%	0
PTD	**Production, Transmission, Distribution**						
	Steam Production	DIR-P	0	0	0	0	0
	Nuclear Production	DIR-P	0	0	0	0	0
	Hydraulic Production	DIR-P	0	0	0	0	0
	Other Production	DIR-P	0	0	0	0	0
	Other Production	DIR-P	0	0	0	0	0
	Other Production	DIR-P	0	0	0	0	0
	Other Items for PTD Ratio Calc.	DIR-P	0	0	0	0	0
	Total Production Plant		0	0	0	0	0
	Transmission Plant	DIR-T	19,168,781	0	19,168,781	0	0
	Other Transmission	DIR-T	0	0	0	0	0
	Other Items for PTD Ratio Calc.	DIR-T	0	0	0	0	0
	Total Transmission Plant	DIR-T	19,168,781	0	19,168,781	0	0
	Total Distribution Plant	DIR-D	406,875,687	0	0	406,875,687	0
	TOTAL		426,044,468	0	19,168,781	406,875,687	0
	RATIO (PTD = PLANT IN SERVICE)		100.00%	0.00%	4.50%	95.50%	0
PTDG	**Production, Transmission, Distribution and General Plant**						
	PTD Total		426,044,468	0	19,168,781	406,875,687	0
	Intangible Plant	PTD	14,308	0	644	13,664	0
	Intangible Plant	PTD	1,115	0	50	1,065	0

	Intangible Plant	PTD	3,586,353	0	161,359	3,424,994	0
	Other Items for PTDG Ratio Calc.	Func. Code	0	0	0	0	0
	GP Total		39,263,380	153,368	1,392,409	37,717,603	0
	TOTAL		468,909,624	153,368	20,723,243	448,033,013	0
	RATIO (PTDG = GROSS PLANT)		100.00%	0.03%	4.42%	95.55%	0
TD	**Transmission, Distribution**						
	Total Transmission Plant	DIR-T	19,168,781	0	19,168,781	0	0
	Total Distribution Plant	DIR-D	406,875,687	0	0	406,875,687	0
	TOTAL		426,044,468	0	19,168,781	406,875,687	0
	RATIO (TD)		100.00%	0.00%	4.50%	95.50%	0
TDG	**Transmission, Distribution and General Plant**						
	Total Transmission Plant	DIR-T	19,168,781	0	19,168,781	0	0
	Total Distribution Plant	DIR-D	406,875,687	0	0	406,875,687	0
	Other T&D Only Items for TDG Calc.	Func. Code	0	0	0	0	0
	Intangible Plant T and D Only	PTD	14308	0	644	13,664	0
	Intangible Plant T and D Only	PTD	1,115	0	50	1,065	0
	Intangible Plant T and D Only	PTD	3,586,353	0	161,359	3,424,994	0
	General Plant Total 389-399(T&D Only)		39,110,012	0	1,392,409	37,717,603	0
	TOTAL		468,756,256	0	20,723,243	448,033,013	0
	RATIO (TDG)		100.00%	0.00%	4.42%	95.58%	0
GPM	**Maintenance of General Plant**						
	Structures and Improvements	PTD/10% TD	18,389,177	0	827,374	17,561,803	0
	Furniture and Equipment	LABOR/10% TD	7,387,614	153,368	1,317	7,232,928	0
	Communication Equipment	PTD	1,574,497	0	70,840	1,503,657	0
	Miscellaneous Equipment	DIR-D	957,429	0	0	957,429	0
	Other Items for GPM Calc.	Func. Code	0	0	0	0	0
	Other Items for GPM Calc.	Func. Code	0	0	0	0	0
	TOTAL		28,308,717	153,368	899,532	27,255,817	0
	RATIO (GPM)		100.00%	0.54%	3.18%	96.28%	0
LABOR	**Labor Ratios**						
	Production	DIR-P	390,044	390,044	0	0	0
	Transmission	DIR-T	3,350	0	3,350	0	0
	Distribution	DIR-D	4,346,429	0	0	4,346,429	0
	Customer Account	DIR-D	4,723,188	0	0	4,723,188	0
	Customer Service	DIR-D	51,072	0	0	51,072	0
	Sales Expense	DIR-D	0	0	0	0	0
	Admin. & General	DIR-D	9,273,993	0	0	9,273,993	0
	Other Labor	Funct. Code	0	0	0	0	0
	Other Labor	Funct. Code	0	0	0	0	0
	TOTAL		18,788,076	390,044	3,350	18,394,682	0
	RATIO (LABOR)		100.00%	2.08%	0.02%	97.91%	0

Functionalization Ratios / DataTabl

10%LABOR	**10.00%**	**0.02%**	**89.98%**
10%TD	**10.00%**	**4.05%**	**85.95%**
DIR-D	**0.00%**	**0.00%**	**100.00%**
DIR-P	**100.00%**	**0.00%**	**0.00%**
DIR-T	**0.00%**	**100.00%**	**0.00%**
DIRECT	**0.00%**	**0.00%**	**0.00%**
GP	**0.39%**	**3.55%**	**96.06%**
GPM	**0.54%**	**3.18%**	**96.28%**
LABOR	**2.08%**	**0.02%**	**97.91%**
PTD	**0.00%**	**4.50%**	**95.50%**
PTDG	**0.03%**	**4.42%**	**95.55%**
TD	**0.00%**	**4.50%**	**95.50%**
TDG	**0.00%**	**4.42%**	**95.58%**

************ RATIO ACRONYMS ************	
10%LABOR	10% to Production, Remainder According to Labor Ratios
10%TD	10% to Production, Remainder According to T/D Ratio
DIR-D	Direct to Distribution
DIR-P	Direct to Production
DIR-T	Direct to Transmission
DIRECT	Direct Allocation
GP	General Plant
GPM	Maintenance of General Plant
LABOR	Labor Ratios
PTD	Production, Transmission, Distribution
PTDG	Production Transmission, Distribution and General Plant
TD	Transmission, Distribution
TDG	Transmission, Distribution and General Plant

When using a functionalization code, you must use these Acronyms. Spelling is crucial, case is irrelevant.

FINAL REPORT Clark Public Utilties

TEST PERIOD:
BPA DOCKET NO. Run No. 12 10-6-05 Base Case
JURISDICTION: LAST APPROVED FILE NUMBER last file
ANALYST NAME: RDG DATE REPORT DUE: 0
DOLLARS IN units

Data Matrix

(1) Account Description	(2) Account No.(s)	(3) Funct. Method	(4) Total	(5) Production	(6) Transmission	(7) Distribution/ Other	(8) Math Check
Schedule 1 (Report Page 1 of 2)							
Production Plant:							
Steam Production	310-316	DIR-P	0	0	0	0	0
Nuclear Production	320-325	DIR-P	0	0	0	0	0
Hydraulic Production	330-336	DIR-P	0	0	0	0	0
Other Production	340-346	DIR-P	0	0	0	0	0
Other Production	340-346	DIR-P	0	0	0	0	0
Other Production	340-346	DIR-P	0	0	0	0	0
Other Production	340-346	DIR-P	0	0	0	0	0
Total Production Plant			0	0	0	0	0
Transmission Plant:							
Transmission Plant	350-359	DIR-T	19,168,781	0	19,168,781	0	0
Other Transmission	Acct. No.	DIR-T	0	0	0	0	0
Other Transmission	Acct. No.	DIR-T	0	0	0	0	0
Total Transmission Plant			19,168,781	0	19,168,781	0	0
Total Distribution Plant	360-373	DIR-D	406,875,687	0	0	406,875,687	0
Intangible Plant	301	PTD	14,308	0	644	13,664	0
Intangible Plant	302	PTD	1,115	0	50	1,065	0
Intangible Plant	303	PTD	3,586,353	0	161,359	3,424,994	0
General Plant:							
Land and Land Rights	389	PTD	489,152	0	22,008	467,144	0
Land and Land Rights	389	10%TD	0	0	0	0	0
Structures and Improvements	390	PTD	18,389,177	0	827,374	17,561,803	0
Structures and Improvements	390	10%TD	0	0	0	0	0
Furniture and Equipment	391	LABOR	7,387,614	153,368	1,317	7,232,928	0
Furniture and Equipment	391	10%TD	0	0	0	0	0
Transportation Equipment	392	TD	8,472,587	0	381,202	8,091,385	0
Transportation Equipment	392	10%TD	0	0	0	0	0
Stores Equipment	393	PTD	313,215	0	14,092	299,123	0
Tools and Garage Equipment	394	PTD	934,984	0	42,067	892,917	0
Laboratory Equipment	395	PTD	344,589	0	15,504	329,085	0
Power Operated Equipment	396	TD	389,289	0	17,515	371,774	0
Communication Equipment	397	PTD	1,574,497	0	70,840	1,503,657	0
Miscellaneous Equipment	398	DIR-D	957,429	0	0	957,429	0
Other Tangible Property	399	PTD	10,847	0	488	10,359	0
Total General Plant			39,263,380	153,368	1,392,409	37,717,603	0
Total Electric Plant In-Service			465,323,271	153,368	20,561,884	444,608,019	0
Less - Depreciation and Amortization:							
Steam Plant	108	DIR-P	0	0	0	0	0
Nuclear Plant	108	DIR-P	0	0	0	0	0
Hydraulic Plant	108	DIR-P	0	0	0	0	0
Other Production Plant	108	DIR-P	0	0	0	0	0
Other Production Plant	108	DIR-P	0	0	0	0	0
Other Production Plant	108	DIR-P	0	0	0	0	0
Other Production Plant	108	DIR-P	0	0	0	0	0
Other Production Plant	108	DIR-P	0	0	0	0	0
Intangible Plant	108	PTD	0	0	0	0	0
Transmission Plant	108	DIR-T	0	0	0	0	0
Other Transmission Plant	108	DIR-T	0	0	0	0	0
Other Transmission Plant	108	DIR-T	0	0	0	0	0
Other Transmission Plant	108	DIR-T	0	0	0	0	0
Distribution Plant	108	DIR-D	171,591,355	0	0	171,591,355	0
General Plant	108	GP	28,335,340	110,682	1,004,865	27,219,794	0
Other Amortization	Acct. No.	Funct. Code	0	0	0	0	0
Amort. Reserve	111	PTD	3,657,068	0	164,540	3,492,528	0
Total Depreciation and Amortization			203,583,763	110,682	1,169,405	202,303,676	0
Total Net Electric Plant In-Service			261,739,508	42,686	19,392,479	242,304,343	0
Schedule 1 (Report Page 2 of 2)							
Add - Debits:							
Cash Working Capital		Direct	0	51,916	463	(52,380)	0
Plant Held Future Use	105	PTDG	0	0	0	0	0
Completed Construction	106	PTD	0	0	0	0	0
CWIP	107-120.1	DIR-D	13,821,782	0	0	13,821,782	0
Acquisitions Adjustments	114	LABOR	0	0	0	0	0
Nuclear Fuel	120.2-120.4	DIR-P	0	0	0	0	0
Investments	123	DIR-D	0	0	0	0	0
Other Investment	124	DIR-D	0	0	0	0	0

Weatherization Investment		DIR-P	301,904	301,904	0	0	0
Fuel Stock	151-152	DIR-P	0	0	0	0	0
Materials and Supplies	153-157,163	TDG	2,367,062	0	104,645	2,262,417	0
Clearing Accounts	184	LABOR	0	0	0	0	0
Misc. Deferred Debits	186	DIR-P	72,518,691	72,518,691	0	0	0
Other Debits	182	DIR-D	0	0	0	0	0
Prepayments	165	DIR-D	332,290	0	0	332,290	0
Total Debits			89,341,729	72,872,511	105,109	16,364,109	0
Less - Credits:							
Cust. Advances for Const.	252	DIR-D	0	0	0	0	0
Other Deferred Credits	253	DIR-D	0	0	0	0	0
Accum Def. Inv. Tax Credit	255	DIR-D	0	0	0	0	0
Deferred Gain - Disposition	256	PTDG	0	0	0	0	0
Unamortized Gain - Reacq.	257	PTDG	0	0	0	0	0
Accum. Def. Income Taxes	281-283	DIR-D	0	0	0	0	0
Other Credits	Acct. No.	Funct. Code	0	0	0	0	0
Other Credits	Acct. No.	Funct. Code	0	0	0	0	0
Total Credits			0	0	0	0	0
Total Rate Base			351,081,237	72,915,198	19,497,588	258,668,452	0
Rate of Return	5.77%						

Schedule 3 (Report Page 1 of 2)

Production Expense:							
Steam - Fuel Exp.	501	DIR-P	0	0	0	0	0
Steam - Operations Exp.	500,502	DIR-P	0	0	0	0	0
Steam - Maintenance	510-514	DIR-P	0	0	0	0	0
Nuclear - Fuel Exp.	518	DIR-P	0	0	0	0	0
Nuclear - Other Exp.	517	DIR-P	0	0	0	0	0
Nuclear - Maintenance	528-532	DIR-P	0	0	0	0	0
Nuclear Research - Misc.	524	DIR-P	0	0	0	0	0
Hydro - Operation Exp.	535-540	DIR-P	0	0	0	0	0
Hydro - Maintenance	541-545	DIR-P	0	0	0	0	0
Other Power - Fuel Exp.	547	DIR-P	0	0	0	0	0
Other Power - Other Exp.	546	DIR-P	0	0	0	0	0
Other - Maintenance Exp.	548-554	DIR-P	0	0	0	0	0
Purchased Power	555	DIR-P	243,949,602	243,949,602	0	0	0
Other Power Supply Exp.	556-557	DIR-P	0	0	0	0	0
Other Prod.	Acct. No.	Funct. Code	0	0	0	0	0
Other Prod.	Acct. No.	Funct. Code	0	0	0	0	0
Other Prod.	Acct. No.	Funct. Code	0	0	0	0	0
Other Prod.	Acct. No.	Funct. Code	0	0	0	0	0
Other Prod.	Acct. No.	Funct. Code	0	0	0	0	0
Total Production Expense			243,949,602	243,949,602	0	0	0
Transmission Expense:							
Wheeling Expense	565	DIR-T	0	0	0	0	0
Trans. Exp. Operations	560-564	DIR-T	0	0	0	0	0
Trans. - Maintenance	568-574	DIR-T	0	0	0	0	0
Other Trans.	Acct. No.	PTD	0	0	0	0	0
Other Trans.	Acct. No.	PTD	0	0	0	0	0
Other Trans.	Acct. No.	Funct. Code	0	0	0	0	0
Total Transmission Expense			0	0	0	0	0
Distribution Expense:							
Dist. - Operations Exp.	580-589	DIR-D	4,628,128	0	0	4,628,128	0
Dist. - Maintenance Exp.	590-598	DIR-D	3,947,746	0	0	3,947,746	0
Other Dist.	Acct. No.	Funct. Code	0	0	0	0	0
Other Dist.	Acct. No.	Funct. Code	0	0	0	0	0
Total Distribution Expense			8,575,874	0	0	8,575,874	0
Customer and Sales Expenses:							
Customer Accounting Expense	901-905	DIR-D	9,060,844	0	0	9,060,844	0
Customer Service Expense	907-910	DIR-D	1,221,898	0	0	1,221,898	0
Sales Expense	911-916	DIR-D	0	0	0	0	0
Total Customer and Sales Expenses			10,282,742	0	0	10,282,742	0
Administration and General Expense:							
Adm. and General Salaries	920	LABOR	8,419,521	174,791	1,501	8,243,229	0
Adm. and General Salaries	920	10%LABOR	0	0	0	0	0
Office supplies & expenses	921	LABOR	2,626,441	54,525	468	2,571,447	0
Office supplies & expenses	921-10%	10%LABOR	0	0	0	0	0
Adm. expenses transfer- Cr.	922	LABOR	(861,320)	(17,881)	(154)	(843,285)	0
Adm. expenses transfer- Cr.	922-10%	10%LABOR	0	0	0	0	0
Outside services employed	923	LABOR	3,291,705	68,336	587	3,222,782	0
Property insurance	924	PTDG	23,737	8	1,049	22,680	0
Injuries and damages	925	LABOR	0	0	0	0	0
Emp. pensions & benefits	926	LABOR	260,665	5,411	46	255,207	0
Franchise requirements	927	DIR-D	0	0	0	0	0
Regulatory Comm. Exp.	928	DIR-D	0	0	0	0	0
Duplicate charges-credit	929	LABOR	0	0	0	0	0
General advertising Exp.	930.1	DIR-D	0	0	0	0	0
Misc. general expenses	930.2	DIR-D	0	0	0	0	0
Misc. general expenses	9.30.2-10%	10%LABOR	1,301,390	130,139	209	1,171,042	0
Rents	931	DIR-D	0	0	0	0	0
Maint. of general plant	932	GPM	0	0	0	0	0
Maint. of general plant	932-10%	10%LABOR	0	0	0	0	0

Other A&G	Acct. No.	Funct. Code	0	0	0	0	0
Other A&G	Acct. No.	Funct. Code	0	0	0	0	0
Total Administration and General Expenses			15,062,139	415,330	3,708	14,643,102	0
Total Operations and Maintenance			277,870,357	244,364,932	3,708	33,501,718	0

Schedule 3 (Report Page 2 of 2)

Depreciation and Amortization:

Steam - Depreciation Exp.	403	DIR-P	0	0	0	0	0
Nuclear - Depreciation Exp.	403	DIR-P	0	0	0	0	0
Hydro. - Depreciation Exp.	403	DIR-P	0	0	0	0	0
Other Prod. - Depreciation	403	DIR-P	0	0	0	0	0
Trans. - Depreciation Exp.	403	DIR-T	0	0	0	0	0
Distr. - Depreciation Exp.	403	DIR-D	18,274,979	0	0	18,274,979	0
Gen. Plant - Depreciation	403	GP	0	0	0	0	0
Other Depreciation Exp.	404	DIR-D	0	0	0	0	0
Amort. Limited Term Plant	405	PTD	0	0	0	0	0
Amort. of Plant Acq.	406	PTD	0	0	0	0	0
Amort. of Prop. Losses	407	PTD	0	0	0	0	0
Other Amort.	Acct. No.	PTDG	0	0	0	0	0
Other Amort.	Acct. No.	Funct. Code	0	0	0	0	0
Other Amort.	Acct. No.	Funct. Code	0	0	0	0	0
Total Depreciation and Amortization			18,274,979	0	0	18,274,979	0

Schedule 3A Items

Fed Tax-Insurance Contrib.	403	LABOR	0	0	0	0	0
Fed Tax-Unemployment		LABOR	0	0	0	0	0
In-lieu Tax		Direct	18,778,677	14,910,021	68,897	3,799,759	0
Other Taxes		DIR-D	0	0	0	0	0
Federal Income Tax		DIR-D	0	0	0	0	0
Total Deferred Taxes		DIR-D	0	0	0	0	0
Miscellaneous Taxes		DIR-D	0	0	0	0	0
Total Non-State Taxes			18,778,677	14,910,021	68,897	3,799,759	0

Washington

State Income Taxes		DIR-D	0	0	0	0	0
State Property Tax		PTDG	0	0	0	0	0
State Unemp. Tax		LABOR	0	0	0	0	0
State Reg. Commis. Tax		DIR-D	0	0	0	0	0
State Generating Tax		DIR-D	0	0	0	0	0
State Pollution Control Tax		DIR-D	0	0	0	0	0
State Revenue and Business Tax		DIR-D	0	0	0	0	0
Local Occupation and Franchise Tax		DIR-D	0	0	0	0	0
Misc Taxes		PTDG	0	0	0	0	0
Other Tax Item		Funct. Code	0	0	0	0	0
Other Tax Item		Funct. Code	0	0	0	0	0

State Two (Put Name Here)

State Income Taxes		DIR-D	0	0	0	0	0
State Property Tax		PTDG	0	0	0	0	0
State Unemp. Tax		LABOR	0	0	0	0	0
State Reg. Commis. Tax		DIR-D	0	0	0	0	0
State Generating Tax		DIR-D	0	0	0	0	0
State Pollution Control Tax		DIR-D	0	0	0	0	0
State Rev. & Business Tax		DIR-D	0	0	0	0	0
Local Occupation & Franchise		DIR-D	0	0	0	0	0
Other Tax Item		Funct. Code	0	0	0	0	0
Other Tax Item		Funct. Code	0	0	0	0	0
Other Tax Item		Funct. Code	0	0	0	0	0
Total State Taxes			0	0	0	0	0
Total Taxes			18,778,677	14,910,021	68,897	3,799,759	0

Schedule 3B Items

Other Included Items:

Gain from Disp. of Plant	411.6	PTDG	0	0	0	0	0
Loss from Disp. of Plant	411.7	PTDG	0	0	0	0	0
Total Disp. of Plant			0	0	0	0	0

Sale from Resale:

Nonfirm Sales for Resale	447	DIR-P	0	0	0	0	0
Firm Sales For Resale	447	DIR-P	0	0	0	0	0
Total Sales from Resale			0	0	0	0	0

Other Revenues:

Forfeited Discounts	450	DIR-P	0	0	0	0	0
Miscellaneous Service Revenues	451	DIR-D	7,768,165	0	0	7,768,165	0
Sales of water/water power	453	DIR-P	0	0	0	0	0
Rent from property	454	DIR-P	0	0	0	0	0
Interdepartmental Rents	455	DIR-P	0	0	0	0	0
Other electric revenues	456	DIR-T	0	0	0	0	0
Billing Credits	0	DIR-P	0	0	0	0	0
Other Revenue	Acct. No.	DIR-D	776,928	0	0	776,928	0
Other Revenue	Acct. No.	DIR-D	554,150	0	0	554,150	0
Total Other Revenues			9,099,243	0	0	9,099,243	0
Total Other Included Items			9,099,243	0	0	9,099,243	0
Total Operating Expenses			305,824,770	259,274,953	72,604	46,477,212	0

Return from Rate Base	Schedule 1	20,247,145	4,205,080	1,124,442	14,917,624	0
Total Cost		326,071,915	263,480,033	1,197,046	61,394,836	0

Schedule 4 Items

Energy Measure - either (MWh) or (kWh)	(kWh)
Total Load (kWh)	4,647,967,387
Non-firm Adjustments (kWh)	0
Other Adjustments (kWh)	0
Distribution Losses (kWh)	0
Excluded Load (kWh)	0
Excl. Load Dist. Losses (kWh)	161,585,926
Excluded Load Costs	0
Revenue Requirement	300,378,529
ASC Multiplier	1,000
Schedule 4 ASC (mills/kWh)	58.9957

Revenue Cap Calculation

	Final Report
Revenue Requirement	300378529
Contract System Costs	264,677,079
Distribution Costs	61,394,836
Amount Exceeds Allowable Costs	25,693,386

End Schedule 4 and Data Matrix

Remainder are Necessary Calculations.

(1) Account Description	(2) Account No.(s)	(3) Funct. Method	(4) Total	(5) Production	(6) Transmission	(7) Distribution/ Other	
Labor Ratio Input:	(source - FERC From 1)						
Production	500-507	DIR-P	390,044	390,044	0	0	0
Transmission	560-573	DIR-T	3,350	0	3,350	0	0
Distribution	580-598	DIR-D	4,346,429	0	0	4,346,429	0
Customer Account	901-905	DIR-D	4,723,188	0	0	4,723,188	0
Customer Service	907-910	DIR-D	51,072	0	0	51,072	0
Sales Expense	911-916	DIR-D	0	0	0	0	0
Admin. & General	920-932	DIR-D	9,273,993	0	0	9,273,993	0
Other Labor	Acct. No.	Funct. Code	0	0	0	0	0
Other Labor	Acct. No.	Funct. Code	0	0	0	0	0
Total Labor			18,788,076	390,044	3,350	18,394,682	0

Functionalization Ratio Schedules

Page 1 of 2

Final Report Ratio Calculations

		Ratio Used	Total Funct.	Production	Transmission	Distribution	Math Check
GP	**Production**						
	Land and Land Rights	PTD/10% TD	489,152	0	22,008	467,144	0
	Structures and Improvements	PTD/10% TD	18,389,177	0	827,374	17,561,803	0
	Furniture and Equipment	LABOR/10% TD	7,387,614	153,368	1,317	7,232,928	0
	Transportation Equipment	TD/10% TD	8,472,587	0	381,202	8,091,385	0
	Stores Equipment	PTD	313,215	0	14,092	299,123	0
	Tools and Garage Equipment	PTD	934,984	0	42,067	892,917	0
	Laboratory Equipment	PTD	344,589	0	15,504	329,085	0
	Power Operated Equipment	TD	389,289	0	17,515	371,774	0
	Communication Equipment	PTD	1,574,497	0	70,840	1,503,657	0
	Miscellaneous Equipment	DIR-D	957,429	0	0	957,429	0
	Other Tangible Property	PTD	10,847	0	488	10,359	0
	Other Items for GP Ratio Calc.	Func. Code	0	0	0	0	0
	Other Items for GP Ratio Calc.	Func. Code	0	0	0	0	0
	Other Items for GP Ratio Calc.	Func. Code	0	0	0	0	0
	TOTAL		39,263,380	153,368	1,392,409	37,717,603	0
	RATIO (GP)		100.00%	0.39%	3.55%	96.06%	0
PTD	**Production, Transmission, Distribution**						
	Steam Production	DIR-P	0	0	0	0	0
	Nuclear Production	DIR-P	0	0	0	0	0
	Hydraulic Production	DIR-P	0	0	0	0	0
	Other Production	DIR-P	0	0	0	0	0
	Other Production	DIR-P	0	0	0	0	0
	Other Production	DIR-P	0	0	0	0	0
	Other Items for PTD Ratio Calc.	DIR-P	0	0	0	0	0
	Total Production Plant		0	0	0	0	0
	Transmission Plant	DIR-T	19,168,781	0	19,168,781	0	0
	Other Transmission	DIR-T	0	0	0	0	0
	Other Items for PTD Ratio Calc.	DIR-T	0	0	0	0	0
	Total Transmission Plant	DIR-T	19,168,781	0	19,168,781	0	0
	Total Distribution Plant	DIR-D	406,875,687	0	0	406,875,687	0
	TOTAL		426,044,468	0	19,168,781	406,875,687	0
	RATIO (PTD = PLANT IN SERVICE)		100.00%	0.00%	4.50%	95.50%	0
PTDG	**Production, Transmission, Distribution and General Plant**						
	PTD Total		426,044,468	0	19,168,781	406,875,687	0
	Intangible Plant	PTD	14,308	0	644	13,664	0

Intangible Plant	PTD	1,115	0	50	1,065	0
Intangible Plant	PTD	3,586,353	0	161,359	3,424,994	0
Other Items for PTDG Ratio Calc.	Func. Code	0	0	0	0	0
GP Total		39,263,380	153,368	1,392,409	37,717,603	0
TOTAL		468,909,624	153,368	20,723,243	448,033,013	0
RATIO (PTDG = GROSS PLANT)		100.00%	0.03%	4.42%	95.55%	0

Functionalization Ratio Schedules

Final Report Ratio Calculations

TD	**Transmission, Distribution**						
	Total Transmission Plant	DIR-T	19,168,781	0	19,168,781	0	0
	Total Distribution Plant	DIR-D	406,875,687	0	0	406,875,687	0
	TOTAL		426,044,468	0	19,168,781	406,875,687	0
	RATIO (TD)		100.00%	0.00%	4.50%	95.50%	0
TDG	**Transmission, Distribution and General Plant**						
	Total Transmission Plant	DIR-T	19,168,781	0	19,168,781	0	0
	Total Distribution Plant	DIR-D	406,875,687	0	0	406,875,687	0
	Other T&D Only Items for TDG Calc.	Func. Code	0	0	0	0	0
	Intangible Plant T and D Only	PTD	14308	0	644	13,664	0
	Intangible Plant T and D Only	PTD	1,115	0	50	1,065	0
	Intangible Plant T and D Only	PTD	3,586,353	0	161,359	3,424,994	0
	General Plant Total 389-399(T&D Only)		39,110,012	0	1,392,409	37,717,603	0
	TOTAL		468,756,256	0	20,723,243	448,033,013	0
	RATIO (TDG)		100.00%	0.00%	4.42%	95.58%	0
GPM	**Maintenance of General Plant**						
	Structures and Improvements	PTD/10% TD	18,389,177	0	827,374	17,561,803	0
	Furniture and Equipment	LABOR/10% TD	7,387,614	153,368	1,317	7,232,928	0
	Communication Equipment	PTD	1,574,497	0	70,840	1,503,657	0
	Miscellaneous Equipment	DIR-D	957,429	0	0	957,429	0
	Other Items for GPM Calc.	Func. Code	0	0	0	0	0
	Other Items for GPM Calc.	Func. Code	0	0	0	0	0
	TOTAL		28,308,717	153,368	899,532	27,255,817	0
	RATIO (GPM)		100.00%	0.54%	3.18%	96.28%	0
LABOR	**Labor Ratios**						
	Production	DIR-P	390,044	390,044	0	0	0
	Transmission	DIR-T	3,350	0	3,350	0	0
	Distribution	DIR-D	4,346,429	0	0	4,346,429	0
	Customer Account	DIR-D	4,723,188	0	0	4,723,188	0
	Customer Service	DIR-D	51,072	0	0	51,072	0
	Sales Expense	DIR-D	0	0	0	0	0
	Admin. & General	DIR-D	9,273,993	0	0	9,273,993	0
	Other Labor	Funct. Code	0	0	0	0	0
	Other Labor	Funct. Code	0	0	0	0	0
	TOTAL		18,788,076	390,044	3,350	18,394,682	0
	RATIO (LABOR)		100.00%	2.08%	0.02%	97.91%	0

Functionalization Ratios / DataTable

10%LABOR	**10.00%**	**0.02%**	**89.98%**
10%TD	**10.00%**	**4.05%**	**85.95%**
DIR-D	**0.00%**	**0.00%**	**100.00%**
DIR-P	**100.00%**	**0.00%**	**0.00%**
DIR-T	**0.00%**	**100.00%**	**0.00%**
DIRECT	**0.00%**	**0.00%**	**0.00%**
GP	**0.39%**	**3.55%**	**96.06%**
GPM	**0.54%**	**3.18%**	**96.28%**
LABOR	**2.08%**	**0.02%**	**97.91%**
PTD	**0.00%**	**4.50%**	**95.50%**
PTDG	**0.03%**	**4.42%**	**95.55%**
TD	**0.00%**	**4.50%**	**95.50%**
TDG	**0.00%**	**4.42%**	**95.58%**

************* RATIO ACRONYMS *************	
10%LABOR	10% to Production, Remainder According to Labor Ratios
10%TD	10% to Production, Remainder According to T/D Ratio
DIR-D	Direct to Distribution
DIR-P	Direct to Production
DIR-T	Direct to Transmission
DIRECT	Direct Allocation
GP	General Plant
GPM	Maintenance of General Plant
LABOR	Labor Ratios
PTD	Production, Transmission, Distribution
PTDG	Production Transmission, Distribution and General Plant
TD	Transmission, Distribution
TDG	Transmission, Distribution and General Plant

When using a functionalization code, you must use these Acronyms. Spelling is crucial, case is irrelevant.

	Clark Public Utilties				Page 1
	Total Cost Comparison				
	Last Approved:last file to	Current As Filed :Run No. 12 10-6-05 Base Case			
		Dollars in units			
		last file	**12 10-6-05 Base Case**	**$ Change**	**% Change**
Production Plant:					
	Steam Production 310-316	0	0	0	0.00%
	Nuclear Production 320-325	0	0	0	0.00%
	Hydraulic Production 330-336	0	0	0	0.00%
	Other Production 340-346	0	0	0	0.00%
	Other Production 340-346	0	0	0	0.00%
	Other Production 340-346	0	0	0	0.00%
	Other Production 340-346	0	0	0	0.00%
Total Production Plant		0	0	0	0.00%
	Transmission Plant 350-359	0	19,168,781	19,168,781	0.00%
	Other Transmission Acct. No.	0	0	0	0.00%
	Other Transmission Acct. No.	0	0	0	0.00%
Total Transmission Plant 350-359		0	19,168,781	19,168,781	0.00%
Total Distribution Plant 360-373		0	406,875,687	406,875,687	0.00%
Intangible Plant 301		0	3,601,776	3,601,776	0.00%
Total General Plant 389-399		0	39,263,380	39,263,380	0.00%
Total Electric Plant In-Service		**$0**	**$465,323,271**	**$465,323,271**	**0.00%**
Less - Depreciation and Amortization:					
	Steam Plant 108	0	0	0	0.00%
	Nuclear Plant 108	0	0	0	0.00%
	Hydraulic Plant 108	0	0	0	0.00%
	Other Production Plant 108	0	0	0	0.00%
	Intangible Plant 108	0	0	0	0.00%
	Transmission Plant 108	0	0	0	0.00%
	Distribution Plant 108	0	171,591,355	171,591,355	0.00%
	General Plant 108	0	28,335,340	28,335,340	0.00%
	Other Amortization Acct. No.	0	0	0	0.00%
	Amort. Reserve 111	0	3,657,068	3,657,068	0.00%
Total Depreciation and Amortization		0	203,583,763	203,583,763	0.00%
Total Net Electric Plant In-Service		**$0**	**$261,739,508**	**$261,739,508**	**0.00%**

	Clark Public Utilties				Page 2
	Total Cost Comparison				
	Last Approved:last file to	Current As Filed :Run No. 12 10-6-05 Base Case			
		Dollars in units			
		last file	12 10-6-05 Base Case	$ Change	% Change
Add - Debits:					
	Cash Working Capital	0	0	0	0.00%
	Plant Held Future Use 105	0	0	0	0.00%
	Completed Construction 106	0	0	0	0.00%
	CWIP 107-120.1	0	13,821,782	13,821,782	0.00%
	Acquisitions Adjustments 114	0	0	0	0.00%
	Nuclear Fuel 120.2-120.4	0	0	0	0.00%
	Investments 123	0	0	0	0.00%
	Other Investment 124	0	0	0	0.00%
	Weatherization Investment	0	301,904	301,904	0.00%
	Fuel Stock 151-152	0	0	0	0.00%
	Materials and Supplies 153-157,163	0	2,367,062	2,367,062	0.00%
	Clearing Accounts 184	0	0	0	0.00%
	Misc. Deferred Debits 186	0	72,518,691	72,518,691	0.00%
	Other Debits 182	0	0	0	0.00%
	Prepayments 165	0	332,290	332,290	0.00%
Total Debits		0	89,341,729	89,341,729	0.00%
Less - Credits:					
	Cust. Advances for Const. 252	0	0	0	0.00%
	Other Deferred Credits 253	0	0	0	0.00%
	Accum Def. Inv. Tax Credit 255	0	0	0	0.00%
	Deferred Gain - Disposition 256	0	0	0	0.00%
	Unamortized Gain - Reacq. 257	0	0	0	0.00%
	Accum. Def. Income Taxes 281-283	0	0	0	0.00%
	Other Credits Acct. No.	0	0	0	0.00%
	Other Credits Acct. No.	0	0	0	0.00%
Total Credits		0	0	0	0.00%
Total Rate Base		$0	$351,081,237	$351,081,237	0.00%
Multiply by Rate of Return:					
Return from Rate Base		$0	$20,247,145	$20,247,145	0.00%

	Clark Public Utilties			Page 3
	Total Cost Comparison			
Last Approved:last file to	Current As Filed :Run No. 12 10-6-05 Base Case			
	Dollars in units			
	last file	**12 10-6-05 Base Case**	**$ Change**	**% Change**
Production Expense				
Fuel 501,518,547	0	0	0	0.00%
Purchased Power 555	0	243,949,602	243,949,602	0.00%
Operations and Maintenance				
Steam 500, 502-14	0	0	0	0.00%
Nuclear 517, 519-32	0	0	0	0.00%
Hydro 535-45	0	0	0	0.00%
Other 546, 548-54, 556-57	0	0	0	0.00%
Total Production Expense	0	243,949,602	243,949,602	0.00%
Transmission 560-73	0	0	0	0.00%
Distribution 580-98	0	8,575,874	8,575,874	0.00%
Customer Accounting Expense 901-905	0	9,060,844	9,060,844	0.00%
Customer Service Expense 907-910	0	1,221,898	1,221,898	0.00%
Sales Expense 911-916	0	0	0	0.00%
Administration and General Expense:				
Adm. and General Salaries 920	0	8,419,521	8,419,521	0.00%
Office supplies & expenses 921	0	2,626,441	2,626,441	0.00%
Adm. expenses transfer- Cr. 922	0	(861,320)	(861,320)	0.00%
Outside services employed 923	0	3,291,705	3,291,705	0.00%
Property insurance 924	0	23,737	23,737	0.00%
Injuries and damages 925	0	0	0	0.00%
Emp. pensions & benefits 926	0	260,665	260,665	0.00%
Franchise requirements 927	0	0	0	0.00%
Regulatory Comm. Exp. 928	0	0	0	0.00%
Duplicate charges-credit 929	0	0	0	0.00%
General advertising Exp. 930.1	0	0	0	0.00%
Misc. general expenses 930.2	0	1,301,390	1,301,390	0.00%
Rents 931	0	0	0	0.00%
Maint. of general plant 932	0	0	0	0.00%
Other A&G Acct. No.	0	0	0	0.00%
Other A&G Acct. No.	0	0	0	0.00%
Total A&G Expense	0	15,062,139	15,062,139	0.00%
Total Operations and Maintenance	**$0**	**$277,870,357**	**$277,870,357**	**0.00%**

	Clark Public Utilties				Page 4
	Total Cost Comparison				
	Last Approved:last file to	Current As Filed :Run No. 12 10-6-05 Base Case			
		Dollars in units			
		last file	**12 10-6-05 Base Case**	**$ Change**	**% Change**
Depreciation and Amortization:					
	Steam - Depreciation Exp. 403	0	0	0	0.00%
	Nuclear - Depreciation Exp. 403	0	0	0	0.00%
	Hydro. - Depreciation Exp. 403	0	0	0	0.00%
	Other Prod. - Depreciation 403	0	0	0	0.00%
	Trans. - Depreciation Exp. 403	0	0	0	0.00%
	Distr. - Depreciation Exp. 403	0	18,274,979	18,274,979	0.00%
	Gen. Plant - Depreciation 403	0	0	0	0.00%
	Other Depreciation Exp. 404	0	0	0	0.00%
	Amortization 404	0	0	0	0.00%
	Other Amort. Acct. No.	0	0	0	0.00%
	Other Amort. Acct. No.	0	0	0	0.00%
Total Depreciation and Amortization		0	18,274,979	18,274,979	0.00%
Add:					
	Taxes Other Than Income Taxes	0	18,778,677	18,778,677	0.00%
	Federal Income Taxes	0	0	0	0.00%
	State Income Taxes	0	0	0	0.00%
Total Taxes		0	18,778,677	18,778,677	0.00%
Less:					
	Sales for Resale	0	0	0	0.00%
	Other Revenues	0	9,099,243	9,099,243	0.00%
	Billing Credits	0	0	0	0.00%
Total Operating Expenses		**$0**	**$305,824,770**	**$305,824,770**	**0.00%**
Return from Rate Base Schedule 1		**$0**	**$20,247,145**	**$20,247,145**	**0.00%**
Total Cost		**$0**	**$326,071,915**	**$326,071,915**	**0.00%**

	Clark Public Utilties				Page 5
	Total Cost Comparison				
	Last Approved:last file to	Current As Filed :Run No. 12 10-6-05 Base Case			
		Dollars in units			
		last file	**12 10-6-05 Base Case**	**$ Change**	**% Change**
	Contract System Costs				
	Production Cost	0	263,480,033	263,480,033	0.00%
	Transmission Cost	0	1,197,046	1,197,046	0.00%
	Less Excluded Costs	0	0	0	0.00%
	Total Contract System Costs	0	264,677,079	264,677,079	0.00%
	Contract System Load				
	Total Load (kWh)	0	4,647,967,387	4,647,967,387	0.00%
	Less:				
	Non-firm Adjustments (kWh)	0	0	0	0.00%
	Other Adjustments (kWh)	0	0	0	0.00%
	Net Load	0	4,647,967,387	4,647,967,387	0.00%
	Plus:				
	Distribution Losses (kWh)	0	0	0	0.00%
	Total Net Load	0	4,647,967,387	4,647,967,387	0.00%
	Less:				
	Excluded Load (kWh)	0	0	0	0.00%
	Excl. Load Dist. Losses (kWh)	0	161,585,926	161,585,926	0.00%
	Total Contract System Load	0	4,486,381,461	4,486,381,461	0.00%
	Average System Cost (mills/kWh)	**$0.00**	**$59.00**	**$59.00**	**0.00%**

	Clark Public Utilties Exchangeable Costs Comparison				Page 1
As Filed:Run No. 12 10-6-05 Base Case		to	Current Cookbook:Run No. 12 10-6-05 Base Case		
		Dollars in units			
	Run No. 12	**10-6-05 Base Case**	**2 10-6-05 Base Case**	**$ Change**	**% Change**
Production Plant:					
	Steam Production 310-316	0	0	0	0.00%
	Nuclear Production 320-325	0	0	0	0.00%
	Hydraulic Production 330-336	0	0	0	0.00%
	Other Production 340-346	0	0	0	0.00%
	Other Production 340-346	0	0	0	0.00%
	Other Production 340-346	0	0	0	0.00%
	Other Production 340-346	0	0	0	0.00%
Total Production Plant		0	0	0	0.00%
	Transmission Plant 350-359	19,168,781	19,168,781	0	0.00%
	Other Transmission Acct. No.	0	0	0	0.00%
	Other Transmission Acct. No.	0	0	0	0.00%
Total Transmission Plant 350-359		19,168,781	19,168,781	0	0.00%
Total Distribution Plant 360-373		0	0	0	0.00%
Intangible Plant 301		162,053	162,053	0	0.00%
Total General Plant 389-399		1,545,777	1,545,777	0	0.00%
Total Electric Plant In-Service		**$20,715,252**	**$20,876,611**	**$161,359**	**0.00%**
Less - Depreciation and Amortization:					
	Steam Plant 108	0	0	0	0.00%
	Nuclear Plant 108	0	0	0	0.00%
	Hydraulic Plant 108	0	0	0	0.00%
	Other Production Plant 108	0	0	0	0.00%
	Intangible Plant 108	0	0	0	0.00%
	Transmission Plant 108	0	0	0	0.00%
	Distribution Plant 108	0	0	0	0.00%
	General Plant 108	1,115,546	1,115,546	0	0.00%
	Other Amortization Acct. No.	0	0	0	0.00%
	Amort. Reserve 111	164,540	164,540	0	0.00%
Total Depreciation and Amortization		1,280,087	1,280,087	0	0.00%
Total Net Electric Plant In-Service		**$19,435,165**	**$19,596,524**	**$161,359**	**0.00%**

	Clark Public Utilties				Page 2
	Exchangeable Costs Comparison				
As Filed:Run No. 12 10-6-05 Base Case		to	Current Cookbook:Run No. 12 10-6-05 Base Case		
		Dollars in units			
	Run No. 12	10-6-05 Base Case	2 10-6-05 Base Case	$ Change	$ Change
Add - Debits:					
	Cash Working Capital	52,380	52,380	0	0.00%
	Plant Held Future Use 105	0	0	0	0.00%
	Completed Construction 106	0	0	0	0.00%
	CWIP 107-120.1	0	0	0	0.00%
	Acquisitions Adjustments 114	0	0	0	0.00%
	Nuclear Fuel 120.2-120.4	0	0	0	0.00%
	Investments 123	0	0	0	0.00%
	Other Investment 124	0	0	0	0.00%
	Weatherization Investment	301,904	301,904	0	0.00%
	Fuel Stock 151-152	0	0	0	0.00%
	Materials and Supplies 153-157,163	104,645	104,645	0	0.00%
	Clearing Accounts 184	0	0	0	0.00%
	Misc. Deferred Debits 186	72,518,691	72,518,691	0	0.00%
	Other Debits 182	0	0	0	0.00%
	Prepayments 165	0	0	0	0.00%
Total Debits		72,977,620	72,977,620	0	0.00%
Less - Credits:					
	Cust. Advances for Const. 252	0	0	0	0.00%
	Other Deferred Credits 253	0	0	0	0.00%
	Accum Def. Inv. Tax Credit 255	0	0	0	0.00%
	Deferred Gain - Disposition 256	0	0	0	0.00%
	Unamortized Gain - Reacq. 257	0	0	0	0.00%
	Accum. Def. Income Taxes 281-283	0	0	0	0.00%
	Other Credits Acct. No.	0	0	0	0.00%
	Other Credits Acct. No.	0	0	0	0.00%
Total Credits		0	0	0	0.00%
Total Rate Base		**$92,412,785**	**$92,574,144**	**$161,359**	**0.17%**
Multiply by Rate of Return:					
Return from Rate Base		**$5,329,522**	**$5,338,827**	**$9,306**	**0.17%**

	Clark Public Utilties				Page 3
	Exchangeable Costs Comparison				
As Filed:Run No. 12 10-6-05 Base Case		to	Current Cookbook:Run No. 12 10-6-05 Base Case		
		Dollars in units			
		Run No. 12 10-6-05 Base Case	**2 10-6-05 Base Case**	**$ Change**	**% Change**
Production Expense					
	Fuel 501,518,547	0	0	0	0.00%
	Purchased Power 555	243,949,602	243,949,602	0	0.00%
Operations and Maintenance					
	Steam 500, 502-14	0	0	0	0.00%
	Nuclear 517, 519-32	0	0	0	0.00%
	Hydro 535-45	0	0	0	0.00%
	Other 546, 548-54, 556-57	0	0	0	0.00%
Total Production Expense		243,949,602	243,949,602	0	0.00%
	Transmission 560-73	0	0	0	0.00%
	Distribution 580-98	0	0	0	0.00%
	Customer Accounting Expense 901-905	0	0	0	0.00%
	Customer Service Expense 907-910	0	0	0	0.00%
	Sales Expense 911-916	0	0	0	0.00%
Administration and General Expense:					
	Adm. and General Salaries 920	176,292	176,292	0	0.00%
	Office supplies & expenses 921	54,994	54,994	0	0.00%
	Adm. expenses transfer- Cr. 922	(18,035)	(18,035)	0	0.00%
	Outside services employed 923	68,923	68,923	0	0.00%
	Property insurance 924	1,057	1,057	0	0.00%
	Injuries and damages 925	0	0	0	0.00%
	Emp. pensions & benefits 926	5,458	5,458	0	0.00%
	Franchise requirements 927	0	0	0	0.00%
	Regulatory Comm. Exp. 928	0	0	0	0.00%
	Duplicate charges-credit 929	0	0	0	0.00%
	General advertising Exp. 930.1	0	0	0	0.00%
	Misc. general expenses 930.2	130,348	130,348	0	0.00%
	Rents 931	0	0	0	0.00%
	Maint. of general plant 932	0	0	0	0.00%
	Other A&G Acct. No.	0	0	0	0.00%
	Other A&G Acct. No.	0	0	0	0.00%
Total A&G Expense		419,037	419,037	0	0.00%
Total Operations and Maintenance		**$244,368,639**	**$244,368,639**	**$0**	**0.00%**

	Clark Public Utilties				Page 4
	Exchangeable Costs Comparison				
As Filed:Run No. 12 10-6-05 Base Case		to	Current Cookbook:Run No. 12 10-6-05 Base Case		
		Dollars in units			
	Run No. 12	**10-6-05 Base Case**	**2 10-6-05 Base Case**	**$ Change**	**% Change**
Depreciation and Amortization:					
	Steam - Depreciation Exp. 403	0	0	0	0.00%
	Nuclear - Depreciation Exp. 403	0	0	0	0.00%
	Hydro. - Depreciation Exp. 403	0	0	0	0.00%
	Other Prod. - Depreciation 403	0	0	0	0.00%
	Trans. - Depreciation Exp. 403	0	0	0	0.00%
	Distr. - Depreciation Exp. 403	0	0	0	0.00%
	Gen. Plant - Depreciation 403	0	0	0	0.00%
	Other Depreciation Exp. 404	0	0	0	0.00%
	Amortization 404	0	0	0	0.00%
	Other Amort. Acct. No.	0	0	0	0.00%
	Other Amort. Acct. No.	0	0	0	0.00%
Total Depreciation and Amortization		0	0	0	0.00%
Add:					
	Taxes Other Than Income Taxes	14,978,918	14,978,918	0	0.00%
	Federal Income Taxes	0	0	0	0.00%
	State Income Taxes	0	0	0	0.00%
Total Taxes		14,978,918	14,978,918	0	0.00%
Less:					
	Sales for Resale	0	0	0	0.00%
	Other Revenues	0	0	0	0.00%
	Billing Credits	0	0	0	0.00%
Total Operating Expenses		**$259,347,557**	**$259,347,557**	**$0**	**0.00%**
Return from Rate Base Schedule 1		**$5,329,522**	**$5,338,827**	**$9,306**	**0.17%**
Total Cost		**$264,677,079**	**$264,686,385**	**$9,306**	**0.00%**

	Clark Public Utilties				Page 5
	Exchangeable Costs Comparison				
As Filed:Run No. 12 10-6-05 Base Case		to	Current Cookbook:Run No. 12 10-6-05 Base Case		
		Dollars in units			
	Run No. 12	**10-6-05 Base Case**	**2 10-6-05 Base Case**	**$ Change**	**% Change**
	Contract System Costs				
	Production Cost	263,480,033	263,480,033	0	0.00%
	Transmission Cost	1,197,046	1,206,352	9,306	0.78%
	Less Excluded Costs	0	0	0	0.00%
	Total Contract System Costs	264,677,079	264,686,385	9,306	0.00%
	Contract System Load				
	Total Load (kWh)	4,647,967,387	4,647,967,387	0	0.00%
	Less:				
	Non-firm Adjustments (kWh)	0	0	0	0.00%
	Other Adjustments (kWh)	0	0	0	0.00%
	Net Load	4,647,967,387	4,647,967,387	0	0.00%
	Plus:				
	Distribution Losses (kWh)	0	0	0	0.00%
	Total Net Load	4,647,967,387	4,647,967,387	0	0.00%
	Less:				
	Excluded Load (kWh)	0	0	0	0.00%
	Excl. Load Dist. Losses (kWh)	161,585,926	161,585,926	0	0.00%
	Total Contract System Load	4,486,381,461	4,486,381,461	0	0.00%
	Average System Cost (mills/kWh)	**$58.9957**	**$58.9957**	**$0.00**	**0.00%**

	Clark Public Utilties Exchangeable Costs Comparison				Page 1
	Last Approved:last file to	Current As Filed :Run No. 12 10-6-05 Base Case			
		Dollars in units			
			last file	2 10-6-05 Base Case	$ Change	% Change
Production Plant:						
	Steam Production	310-316	0	0	0	0.00%
	Nuclear Production	320-325	0	0	0	0.00%
	Hydraulic Production	330-336	0	0	0	0.00%
	Other Production	340-346	0	0	0	0.00%
	Other Production	340-346	0	0	0	0.00%
	Other Production	340-346	0	0	0	0.00%
	Other Production	340-346	0	0	0	0.00%
Total Production Plant			0	0	0	0.00%
	Transmission Plant	350-359	0	19,168,781	19,168,781	0.00%
	Other Transmission	Acct. No.	0	0	0	0.00%
	Other Transmission	Acct. No.	0	0	0	0.00%
Total Transmission Plant 350-359			0	19,168,781	19,168,781	0.00%
Total Distribution Plant 360-373			0	0	0	0.00%
Intangible Plant 301			0	162,053	162,053	0.00%
Total General Plant 389-399			0	1,545,777	1,545,777	0.00%
Total Electric Plant In-Service			$0	$20,715,252	$20,715,252	0.00%
Less - Depreciation and Amortization:						
	Steam Plant	108	0	0	0	0.00%
	Nuclear Plant	108	0	0	0	0.00%
	Hydraulic Plant	108	0	0	0	0.00%
	Other Production Plant	108	0	0	0	0.00%
	Intangible Plant	108	0	0	0	0.00%
	Transmission Plant	108	0	0	0	0.00%
	Distribution Plant	108	0	0	0	0.00%
	General Plant	108	0	1,115,546	1,115,546	0.00%
	Other Amortization	Acct. No.	0	0	0	0.00%
	Amort. Reserve	111	0	164,540	164,540	0.00%
Total Depreciation and Amortization			0	1,280,087	1,280,087	0.00%
Total Net Electric Plant In-Service			$0	$19,435,165	$19,435,165	0.00%

	Clark Public Utilties			Page 2
	Exchangeable Costs Comparison			
Last Approved:last file to	Current As Filed :Run No. 12 10-6-05 Base Case			
	Dollars in units			
	last file	2 10-6-05 Base Case	$ Change	% Change
Add - Debits:				
Cash Working Capital	0	52,380	52,380	0.00%
Plant Held Future Use 105	0	0	0	0.00%
Completed Construction 106	0	0	0	0.00%
CWIP 107-120.1	0	0	0	0.00%
Acquisitions Adjustments 114	0	0	0	0.00%
Nuclear Fuel 120.2-120.4	0	0	0	0.00%
Investments 123	0	0	0	0.00%
Other Investment 124	0	0	0	0.00%
Weatherization Investment	0	301,904	301,904	0.00%
Fuel Stock 151-152	0	0	0	0.00%
Materials and Supplies 153-157,163	0	104,645	104,645	0.00%
Clearing Accounts 184	0	0	0	0.00%
Misc. Deferred Debits 186	0	72,518,691	72,518,691	0.00%
Other Debits 182	0	0	0	0.00%
Prepayments 165	0	0	0	0.00%
Total Debits	0	72,977,620	72,977,620	0.00%
Less - Credits:				
Cust. Advances for Const. 252	0	0	0	0.00%
Other Deferred Credits 253	0	0	0	0.00%
Accum Def. Inv. Tax Credit 255	0	0	0	0.00%
Deferred Gain - Disposition 256	0	0	0	0.00%
Unamortized Gain - Reacq. 257	0	0	0	0.00%
Accum. Def. Income Taxes 281-283	0	0	0	0.00%
Other Credits Acct. No.	0	0	0	0.00%
Other Credits Acct. No.	0	0	0	0.00%
Total Credits	0	0	0	0.00%
Total Rate Base	$0	$92,412,785	$92,412,785	0.00%
Multiply by Rate of Return:				
Return from Rate Base	$0	$5,329,522	$5,329,522	0.00%

					Page 3
	Clark Public Utilties				
	Exchangeable Costs Comparison				
	Last Approved:last file to	Current As Filed :Run No. 12 10-6-05 Base Case			
		Dollars in units			
		last file	**2 10-6-05 Base Case**	**$ Change**	**% Change**
Production Expense					
	Fuel 501,518,547	0	0	0	0.00%
	Purchased Power 555	0	243,949,602	243,949,602	0.00%
Operations and Maintenance					
	Steam 500, 502-14	0	0	0	0.00%
	Nuclear 517, 519-32	0	0	0	0.00%
	Hydro 535-45	0	0	0	0.00%
	Other 546, 548-54, 556-57	0	0	0	0.00%
Total Production Expense		0	243,949,602	243,949,602	0.00%
	Transmission 560-73	0	0	0	0.00%
	Distribution 580-98	0	0	0	0.00%
	Customer Accounting Expense 901-905	0	0	0	0.00%
	Customer Service Expense 907-910	0	0	0	0.00%
	Sales Expense 911-916	0	0	0	0.00%
Administration and General Expense:					
	Adm. and General Salaries 920	0	176,292	176,292	0.00%
	Office supplies & expenses 921	0	54,994	54,994	0.00%
	Adm. expenses transfer- Cr. 922	0	(18,035)	(18,035)	0.00%
	Outside services employed 923	0	68,923	68,923	0.00%
	Property insurance 924	0	1,057	1,057	0.00%
	Injuries and damages 925	0	0	0	0.00%
	Emp. pensions & benefits 926	0	5,458	5,458	0.00%
	Franchise requirements 927	0	0	0	0.00%
	Regulatory Comm. Exp. 928	0	0	0	0.00%
	Duplicate charges-credit 929	0	0	0	0.00%
	General advertising Exp. 930.1	0	0	0	0.00%
	Misc. general expenses 930.2	0	130,348	130,348	0.00%
	Rents 931	0	0	0	0.00%
	Maint. of general plant 932	0	0	0	0.00%
	Other A&G Acct. No.	0	0	0	0.00%
	Other A&G Acct. No.	0	0	0	0.00%
Total A&G Expense		0	419,037	419,037	0.00%
Total Operations and Maintenance		$0	$244,368,639	$244,368,639	0.00%

	Clark Public Utilties				Page 4
	Exchangeable Costs Comparison				
	Last Approved:last file to	Current As Filed :Run No. 12 10-6-05 Base Case			
		Dollars in units			
		last file	**2 10-6-05 Base Case**	**$ Change**	**% Change**
Depreciation and Amortization:					
	Steam - Depreciation Exp. 403	0	0	0	0.00%
	Nuclear - Depreciation Exp. 403	0	0	0	0.00%
	Hydro. - Depreciation Exp. 403	0	0	0	0.00%
	Other Prod. - Depreciation 403	0	0	0	0.00%
	Trans. - Depreciation Exp. 403	0	0	0	0.00%
	Distr. - Depreciation Exp. 403	0	0	0	0.00%
	Gen. Plant - Depreciation 403	0	0	0	0.00%
	Other Depreciation Exp. 404	0	0	0	0.00%
	Amortization 404	0	0	0	0.00%
	Other Amort. Acct. No.	0	0	0	0.00%
	Other Amort. Acct. No.	0	0	0	0.00%
Total Depreciation and Amortization		0	0	0	0.00%
Add:					
	Taxes Other Than Income Taxes	0	14,978,918	14,978,918	0.00%
	Federal Income Taxes	0	0	0	0.00%
	State Income Taxes	0	0	0	0.00%
Total Taxes		0	14,978,918	14,978,918	0.00%
Less:					
	Sales for Resale	0	0	0	0.00%
	Other Revenues	0	0	0	0.00%
	Billing Credits	0	0	0	0.00%
Total Operating Expenses		**$0**	**$259,347,557**	**$259,347,557**	**0.00%**
Return from Rate Base Schedule 1		**$0**	**$5,329,522**	**$5,329,522**	**0.00%**
Total Cost		**$0**	**$264,677,079**	**$264,677,079**	**0.00%**

Clark Public Utilties				Page 5
Exchangeable Costs Comparison				
Last Approved:last file to	Current As Filed :Run No. 12 10-6-05 Base Case			
	Dollars in units			
	last file	**2 10-6-05 Base Case**	**$ Change**	**% Change**
Contract System Costs				
Production Cost	0	263,480,033	263,480,033	0.00%
Transmission Cost	0	1,197,046	1,197,046	0.00%
Less Excluded Costs	0	0	0	0.00%
Total Contract System Costs	0	264,677,079	264,677,079	0.00%
Contract System Load				
Total Load (kWh)	0	4,647,967,387	4,647,967,387	0.00%
Less:				
Non-firm Adjustments (kWh)	0	0	0	0.00%
Other Adjustments (kWh)	0	0	0	0.00%
Net Load	0	4,647,967,387	4,647,967,387	0.00%
Plus:				
Distribution Losses (kWh)	0	0	0	0.00%
Total Net Load	0	4,647,967,387	4,647,967,387	0.00%
Less:				
Excluded Load (kWh)	0	0	0	0.00%
Excl. Load Dist. Losses (kWh)	0	161,585,926	161,585,926	0.00%
Total Contract System Load	0	4,486,381,461	4,486,381,461	0.00%
Average System Cost (mills/kWh)	**$0.00**	**$59.00**	**$59.00**	**0.00%**

Appendix 1	Clark Public Utilties	Schedule 1
Page 1	Residential Purchase and Sale Agreement	Page 1 of 2
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	Plant Investment/Rate Base/Rate of Return	
	Dollars in units	

Line Number	Account Decription		Total to be Functionalized	Functionalized Amount Production	Transmisison	Distribution
	Production Plant:					
1	Steam Production	310-316	0	0	0	0
2	Nuclear Production	320-325	0	0	0	0
3	Hydraulic Production	330-336	0	0	0	0
4	Other Production	340-346	0	0	0	0
5	Other Production	340-346	0	0	0	0
6	Other Production	340-346	0	0	0	0
7	Other Production	340-346	0	0	0	0
8	**Total Production Plant**		0	0	0	0
9	Transmission Plant	350-359	0	0	0	0
10	Other Transmission	Acct. No.	0	0	0	0
11	Other Transmission	Acct. No.	0	0	0	0
12	**Total Transmission Plant 350-359**		0	0	0	0
13	**Total Distribution Plant 360-373**		0	0	0	0
14	**Intangible Plant 301**		0	0	0	0
15	**Total General Plant 389-399**		0	0	0	0
16	**Total Electric Plant In-Service**		0	0	0	0
	Less - Depreciation and Amortization:					
17	Steam Plant	108	0	0	0	0
18	Nuclear Plant	108	0	0	0	0
19	Hydraulic Plant	108	0	0	0	0
20	Other Production Plant	108	0	0	0	0
21	Intangible Plant	108	0	0	0	0
22	Transmission Plant	108	0	0	0	0
23	Distribution Plant	108	0	0	0	0
24	General Plant	108	0	0	0	0
25	Other Amortization	Acct. No.	0	0	0	0
26	Amort. Reserve	111	0	0	0	0
27	**Total Depreciation and Amortization**		0	0	0	0
28	**Total Net Electric Plant In-Service**		$0	$0	$0	$0

Appendix 1	Clark Public Utilties				Schedule 1
Page 2	Residential Purchase and Sale Agreement				Page 2 of 2
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	Plant Investment/Rate Base/Rate of Return				
	Dollars in units				

			Functionalized Amount		
Line Number	Account Decription	Total to be Functionalized	Production	Transmisison	Distribution
	Add - Debits:				
29	Cash Working Capital	0	0	0	0
30	Plant Held Future Use 105	0	0	0	0
31	Completed Construction 106	0	0	0	0
32	CWIP 107-120.1	0	0	0	0
33	Acquisitions Adjustments 114	0	0	0	0
34	Nuclear Fuel 120.2-120.4	0	0	0	0
35	Investments 123	0	0	0	0
36	Other Investment 124	0	0	0	0
37	Weatherization Investment	0	0	0	0
38	Fuel Stock 151-152	0	0	0	0
39	Materials and Supplies 153-157,163	0	0	0	0
40	Clearing Accounts 184	0	0	0	0
41	Misc. Deferred Debits 186	0	0	0	0
42	Other Debits 182	0	0	0	0
43	Prepayments 165	0	0	0	0
44	**Total Debits**	0	0	0	0
	Less - Credits:				
45	Cust. Advances for Const. 252	0	0	0	0
46	Other Deferred Credits 253	0	0	0	0
47	Accum Def. Inv. Tax Credit 255	0	0	0	0
48	Deferred Gain - Disposition 256	0	0	0	0
49	Unamortized Gain - Reacq. 257	0	0	0	0
50	Accum. Def. Income Taxes 281-283	0	0	0	0
51	Other Credits Acct. No.	0	0	0	0
52	Other Credits Acct. No.	0	0	0	0
53	**Total Credits**	0	0	0	0
54	**Total Rate Base**	$0	$0	$0	$0
	Rate of Return: 0.00%				
55	**Return from Rate Base**	$0	$0	$0	$0

Appendix 1	Clark Public Utilties				Schedule 3
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	Jurisdiction: Clark Public Utilities				
	Test Period: October 1, 2005 - September 31, 2006				
	BPA Docket Number: last file				
	Expenses				
	Dollars in units				

Line Number	Account Decription		Total to be Functionalized	Functionalized Amount Production	Transmisison	Distribution
	Production Expense:					
1	Fuel 501,518,547		0	0	0	0
2	Purchased Power 555		0	0	0	0
	Operations and Maintenance:					
3	Steam 500, 502-14		0	0	0	0
4	Nuclear 517, 519-32		0	0	0	0
5	Hydro 535-45		0	0	0	0
6	Other 546, 548-54, 556-57		0	0	0	0
7	**Total Production Expense**		**0**	**0**	**0**	**0**
8	Transmission 560-73		0	0	0	0
9	Distribution 580-98		0	0	0	0
10	Customer Accounting Exp. 901-905	Check Line-Item	0	0	0	0
11	Customer Service Exp. 907-910	Check Line-Item	0	0	0	0
12	Sales Expense 911-916		0	0	0	0
	Administration and General Expense:					
13	Adm. and General Salaries 920		0	0	0	0
14	Office supplies & expenses 921		0	0	0	0
15	Adm. expenses transfer- Cr. 922		0	0	0	0
16	Outside services employed 923		0	0	0	0
17	Property insurance 924		0	0	0	0
18	Injuries and damages 925		0	0	0	0
19	Emp. pensions & benefits 926		0	0	0	0
20	Franchise requirements 927		0	0	0	0
21	Regulatory Comm. Exp. 928		0	0	0	0
22	Duplicate charges-credit 929		0	0	0	0
23	General advertising Exp. 930.1		0	0	0	0
24	Misc. general expenses 930.2		0	0	0	0
25	Rents 931		0	0	0	0
26	Maint. of general plant 932		0	0	0	0
27	Other A&G Acct. No.		0	0	0	0
28	Other A&G Acct. No.		0	0	0	0
29	**Total A&G Expense**		**0**	**0**	**0**	**0**
30	**Total Operations and Maintenance**		**$0**	**$0**	**$0**	**$0**

Appendix 1	Clark Public Utilties			Schedule 3
Page 4	Residential Purchase and Sale Agreement			Page 2 of 2
	LAST APPROVED			
	Jurisdiction: Clark Public Utilities			
	Test Period: October 1, 2005 - September 31, 2006			
	BPA Docket Number: last file			
	Expenses			
	Dollars in units			

Line Number	Account Decription	Total to be Functionalized	Production	Functionalized Amount Transmisison	Distribution
	Depreciation and Amortization:				
31	Steam - Depreciation Exp. 403	0	0	0	0
32	Nuclear - Depreciation Exp. 403	0	0	0	0
33	Hydro. - Depreciation Exp. 403	0	0	0	0
34	Other Prod. - Depreciation 403	0	0	0	0
35	Trans. - Depreciation Exp. 403	0	0	0	0
36	Distr. - Depreciation Exp. 403	0	0	0	0
37	Gen. Plant - Depreciation 403	0	0	0	0
38	Other Depreciation Exp. 404	0	0	0	0
39	Amortization 404	0	0	0	0
40	Other Amort. Acct. No.	0	0	0	0
41	Other Amort. Acct. No.	0	0	0	0
42	**Total Depreciation and Amortization**	**0**	**0**	**0**	**0**
	Add:				
43	Taxes Other Than Income Taxes	0	0	0	0
44	Federal Income Taxes	0	0	0	0
45	State Income Taxes	0	0	0	0
46	**Total Taxes**	**0**	**0**	**0**	**0**
	Less:				
47	Sales for Resale	0	0	0	0
48	Other Revenues	0	0	0	0
49	Billing Credits	0	0	0	0
50	**Total Operating Expenses**	**$0**	**$0**	**$0**	**$0**
51	**Return from Rate Base Schedule 1**	**$0**	**$0**	**$0**	**$0**
52	**Total Cost**	**$0**	**$0**	**$0**	**$0**

Appendix 1	**Clark Public Utilties**					Schedule 3A
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	LAST APPROVED					
	Jurisdiction: Clark Public Utilities					
	Test Period: October 1, 2005 - September 31, 2006					
	BPA Docket Number: last file					
	All Taxes					
	Dollars in units					

Line Number	Account Decription		Total to be Functionalized	Production	Functionalized Amount Transmisison	Distribution
1	Fed Tax-Insurance Contrib.		0	0	0	0
2	Fed Tax-Unemployment		0	0	0	0
3	In-lieu Tax		0	0	0	0
4	Other Taxes		0	0	0	0
5	Federal Income Tax		0	0	0	0
6	Total Deferred Taxes		0	0	0	0
7	Miscellaneous Taxes		0	0	0	0
	State One (Put name here)					
8	State Income Taxes		0	0	0	0
9	State Property Tax		0	0	0	0
10	State Unemp. Tax		0	0	0	0
11	State Reg. Commis. Tax		0	0	0	0
12	State Generating Tax		0	0	0	0
13	State Pollution Control Tax		0	0	0	0
14	State Revenue and Business Tax		0	0	0	0
15	Local Occupation and Franchise Tax		0	0	0	0
16	Other Tax Item	Check Line-Item	0	0	0	0
17	Other Tax Item		0	0	0	0
18	Other Tax Item		0	0	0	0
	State Two (Put Name Here)					
19	State Income Taxes		0	0	0	0
20	State Property Tax		0	0	0	0
21	State Unemp. Tax		0	0	0	0
22	State Reg. Commis. Tax		0	0	0	0
23	State Generating Tax		0	0	0	0
24	State Pollution Control Tax		0	0	0	0
25	State Rev. & Business Tax		0	0	0	0
26	Local Occupation & Franchise		0	0	0	0
27	Other Tax Item		0	0	0	0
28	Other Tax Item		0	0	0	0
29	Other Tax Item		0	0	0	0
30	**Total Taxes**		$0	$0	$0	$0

Appendix 1		Clark Public Utilties				Schedule 3B
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		LAST APPROVED				
		Jurisdiction: Clark Public Utilities				
		Test Period: October 1, 2005 - September 31, 2006				
		BPA Docket Number: last file				
		Other Included Items				
		Dollars in units				

Line Number	Account Decription		Total to be Functionalized	Functionalized Amount Production	Transmisison	Distribution
1		Gain from Disp. of Plant 411.6	0	0	0	0
2		Loss from Disp. of Plant 411.7	0	0	0	0
3	**Total Disp. of Plant**		**0**	**0**	**0**	**0**
	Sale from Resale:					
4		Nonfirm Sales for Resale 447	0	0	0	0
5		Firm Sales For Resale 447	0	0	0	0
6	**Total Sales from Resale**		**0**	**0**	**0**	**0**
	Other Revenues:					
7		Forfeited Discounts 450	0	0	0	0
8		Miscellaneous Service Revenues 451	0	0	0	0
9		Sales of water/water power 453	0	0	0	0
10		Rent from property 454	0	0	0	0
11		Interdepartmental Rents 455	0	0	0	0
12		Other electric revenues 456	0	0	0	0
13		Billing Credits	0	0	0	0
14		Other Revenue Acct. No.	0	0	0	0
15		Other Revenue Acct. No.	0	0	0	0
16	**Total Other Revenues**		**0**	**0**	**0**	**0**
17	**Total Other Included Items**		**$0**	**$0**	**$0**	**$0**

Appendix 1	Clark Public Utilties	Schedule 4
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	LAST APPROVED	
	Jurisdiction: Clark Public Utilities	
	Test Period: October 1, 2005 - September 31, 2006	
	BPA Docket Number: last file	
	Average System Cost	
	Dollars in units	

Line Number	Account Decription	Amount
	Contract System Costs	
1	Production Cost	0
2	Transmission Cost	0
3	Less Excluded Costs	0
4	**Total Contract System Costs**	0
	Contract System Load	
6	Total Load (kWh)	0
	Less:	
7	Non-firm Adjustments (kWh)	0
8	Other Adjustments (kWh)	0
9	**Net Load**	0
	Plus:	
10	Distribution Losses (kWh)	0
11	**Total Net Load**	0
	Less:	
12	Excluded Load (kWh)	0
13	Excl. Load Dist. Losses (kWh)	0
14	**Total Contract System Load**	0
15	**Average System Cost (mills/kWh)**	0.00

Appendix 1	Clark Public Utilties	Miscellaneous
Page 8	Residential Purchase and Sale Agreement	Page 1 of 1
	LAST APPROVED	
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	Test Period: October 1, 2005 - September 31, 2006	
	BPA Docket Number: last file	
	Dollars in units	

Line Number	Account Decription	Total to be Functionalized	Functionalized Amount Production	Transmisison	Distribution
	General Plant: 389-399				
1	Land and Land Rights 389	0	0	0	0
2	Land and Land Rights 389	0	0	0	0
3	Structures and Improvements 390	0	0	0	0
4	Structures and Improvements 390	0	0	0	0
5	Furniture and Equipment 391	0	0	0	0
6	Furniture and Equipment 391	0	0	0	0
7	Transportation Equipment 392	0	0	0	0
8	Transportation Equipment 392	0	0	0	0
9	Stores Equipment 393	0	0	0	0
10	Tools and Garage Equipment 394	0	0	0	0
11	Laboratory Equipment 395	0	0	0	0
12	Power Operated Equipment 396	0	0	0	0
13	Communication Equipment 397	0	0	0	0
14	Miscellaneous Equipment 398	0	0	0	0
15	Other Tangible Property 399	0	0	0	0
16	**Total General Plant 389-399**	**0**	**0**	**0**	**0**
	Labor Ratio Input:				
17	Production 500-507	0	0	0	0
18	Transmission 560-573	0	0	0	0
19	Distribution 580-598	0	0	0	0
20	Customer Account 901-905	0	0	0	0
21	Customer Service 907-910	0	0	0	0
22	Sales Expense 911-916	0	0	0	0
23	Admin. & General 920-932	0	0	0	0
24	Other Labor Acct. No.	0	0	0	0
25	Other Labor Acct. No.	0	0	0	0
26	**Total Labor**	**0**	**0**	**0**	**0**

Clark Public Utilties

Residential Purchase and Sale Agreement
COOKBOOK
Jurisdiction: Clark Public Utilities

Test Period: October 1, 2005 - September 31, 2006
BPA Docket Number: Run No. 12 10-6-05 Base Case
Plant Investment/Rate Base/Rate of Return
Dollars in units

Line Number	Account Decription		Total to be Functionalized	Functionalized Amount		
				Production	Transmisison	Distribution
	Production Plant:					
1	Steam Production	310-316	0	0	0	0
2	Nuclear Production	320-325	0	0	0	0
3	Hydraulic Production	330-336	0	0	0	0
4	Other Production	340-346	0	0	0	0
5	Other Production	340-346	0	0	0	0
6	Other Production	340-346	0	0	0	0
7	Other Production	340-346	0	0	0	0
8	**Total Production Plant**		**0**	**0**	**0**	**0**
9	Transmission Plant	350-359	19,168,781	0	19,168,781	0
10	Other Transmission	Acct. No.	0	0	0	0
11	Other Transmission	Acct. No.	0	0	0	0
12	**Total Transmission Plant 350-359**		**19,168,781**	**0**	**19,168,781**	**0**
13	**Total Distribution Plant 360-373**		406,875,687	0	0	406,875,687
14	**Intangible Plant 301**		3,601,776	0	162,053	3,439,723
15	**Total General Plant 389-399**		39,263,380	153,368	1,392,409	37,717,603
16	**Total Electric Plant In-Service**		**468,909,624**	**153,368**	**20,723,243**	**448,033,013**
	Less - Depreciation and Amortization:					
17	Steam Plant	108	0	0	0	0
18	Nuclear Plant	108	0	0	0	0
19	Hydraulic Plant	108	0	0	0	0
20	Other Production Plant	108	0	0	0	0
21	Intangible Plant	108	0	0	0	0
22	Transmission Plant	108	0	0	0	0
23	Distribution Plant	108	171,591,355	0	0	171,591,355
24	General Plant	108	28,335,340	110,682	1,004,865	27,219,794
25	Other Amortization	Acct. No.	0	0	0	0
26	Amort. Reserve	111	3,657,068	0	164,540	3,492,528
27	**Total Depreciation and Amortization**		**203,583,763**	**110,682**	**1,169,405**	**202,303,676**
28	**Total Net Electric Plant In-Service**		**$265,325,861**	**$42,686**	**$19,553,838**	**$245,729,337**

Clark Public Utilties

Residential Purchase and Sale Agreement
COOKBOOK
Jurisdiction: Clark Public Utilities

Test Period: October 1, 2005 - September 31, 2006
BPA Docket Number: Run No. 12 10-6-05 Base Case
Plant Investment/Rate Base/Rate of Return
Dollars in units

Line Number	Account Decription	Total to be Functionalized	Functionalized Amount Production	Transmisison	Distribution
	Add - Debits:				
29	Cash Working Capital	0	51,916	463	(52,380)
30	Plant Held Future Use 105	0	0	0	0
31	Completed Construction 106	0	0	0	0
32	CWIP 107-120.1	13,821,782	0	0	13,821,782
33	Acquisitions Adjustments 114	0	0	0	0
34	Nuclear Fuel 120.2-120.4	0	0	0	0
35	Investments 123	0	0	0	0
36	Other Investment 124	0	0	0	0
37	Weatherization Investment	301,904	301,904	0	0
38	Fuel Stock 151-152	0	0	0	0
39	Materials and Supplies 153-157,163	2,367,062	0	104,645	2,262,417
40	Clearing Accounts 184	0	0	0	0
41	Misc. Deferred Debits 186	72,518,691	72,518,691	0	0
42	Other Debits 182	0	0	0	0
43	Prepayments 165	332,290	0	0	332,290
44	**Total Debits**	**89,341,729**	**72,872,511**	**105,109**	**16,364,109**
	Less - Credits:				
45	Cust. Advances for Const. 252	0	0	0	0
46	Other Deferred Credits 253	0	0	0	0
47	Accum Def. Inv. Tax Credit 255	0	0	0	0
48	Deferred Gain - Disposition 256	0	0	0	0
49	Unamortized Gain - Reacq. 257	0	0	0	0
50	Accum. Def. Income Taxes 281-283	0	0	0	0
51	Other Credits Acct. No.	0	0	0	0
52	Other Credits Acct. No.	0	0	0	0
53	**Total Credits**	**0**	**0**	**0**	**0**
54	**Total Rate Base**	**$354,667,590**	**$72,915,198**	**$19,658,946**	**$262,093,446**
	Rate of Return: **5.77%**				
55	**Return from Rate Base**	**$20,453,973**	**$4,205,080**	**$1,133,748**	**$15,115,146**

Clark Public Utilties
Residential Purchase and Sale Agreement
COOKBOOK
Jurisdiction: Clark Public Utilities

Test Period: October 1, 2005 - September 31, 2006
BPA Docket Number: Run No. 12 10-6-05 Base Case
Expenses
Dollars in units

Line Number	Account Decription		Total to be Functionalized	Functionalized Amount Production	Transmisison	Distribution
	Production Expense:					
1	Fuel	501,518,547	0	0	0	0
2	Purchased Power	555	243,949,602	243,949,602	0	0
	Operations and Maintenance:					
3	Steam	500, 502-14	0	0	0	0
4	Nuclear	517, 519-32	0	0	0	0
5	Hydro	535-45	0	0	0	0
6	Other	546, 548-54, 556-57	0	0	0	0
7	**Total Production Expense**		**243,949,602**	**243,949,602**	**0**	**0**
8	Transmission	560-73	0	0	0	0
9	Distribution	580-98	8,575,874	0	0	8,575,874
10	Customer Accounting Expense	901-905	9,060,844	0	0	9,060,844
11	Customer Service Expense	907-910	1,221,898	0	0	1,221,898
12	Sales Expense	911-916	0	0	0	0
	Administration and General Expense:					
13	Adm. and General Salaries	920	8,419,521	174,791	1,501	8,243,229
14	Office supplies & expenses	921	2,626,441	54,525	468	2,571,447
15	Adm. expenses transfer- Cr.	922	(861,320)	(17,881)	(154)	(843,285)
16	Outside services employed	923	3,291,705	68,336	587	3,222,782
17	Property insurance	924	23,737	8	1,049	22,680
18	Injuries and damages	925	0	0	0	0
19	Emp. pensions & benefits	926	260,665	5,411	46	255,207
20	Franchise requirements	927	0	0	0	0
21	Regulatory Comm. Exp.	928	0	0	0	0
22	Duplicate charges-credit	929	0	0	0	0
23	General advertising Exp.	930.1	0	0	0	0
24	Misc. general expenses	930.2	1,301,390	130,139	209	1,171,042
25	Rents	931	0	0	0	0
26	Maint. of general plant	932	0	0	0	0
27	Other A&G	Acct. No.	0	0	0	0
28	Other A&G	Acct. No.	0	0	0	0
29	**Total A&G Expense**		**15,062,139**	**415,330**	**3,708**	**14,643,102**
30	**Total Operations and Maintenance**		**$277,870,357**	**$244,364,932**	**$3,708**	**$33,501,718**

Clark Public Utilties

Residential Purchase and Sale Agreement
COOKBOOK
Jurisdiction: Clark Public Utilities

Test Period: October 1, 2005 - September 31, 2006
BPA Docket Number: Run No. 12 10-6-05 Base Case
Expenses
Dollars in units

Line Number	Account Decription		Total to be Functionalized	Functionalized Amount Production	Transmisison	Distribution
	Depreciation and Amortization:					
31	Steam - Depreciation Exp.	403	0	0	0	0
32	Nuclear - Depreciation Exp.	403	0	0	0	0
33	Hydro. - Depreciation Exp.	403	0	0	0	0
34	Other Prod. - Depreciation	403	0	0	0	0
35	Trans. - Depreciation Exp.	403	0	0	0	0
36	Distr. - Depreciation Exp.	403	18,274,979	0	0	18,274,979
37	Gen. Plant - Depreciation	403	0	0	0	0
38	Other Depreciation Exp.	404	0	0	0	0
39	Amortization	404	0	0	0	0
40	Other Amort.	Acct. No.	0	0	0	0
41	Other Amort.	Acct. No.	0	0	0	0
42	**Total Depreciation and Amortization**		**18,274,979**	**0**	**0**	**18,274,979**
	Add:					
43	Taxes Other Than Income Taxes		18,778,677	14,910,021	68,897	3,799,759
44	Federal Income Taxes		0	0	0	0
45	State Income Taxes		0	0	0	0
46	**Total Taxes**		**18,778,677**	**14,910,021**	**68,897**	**3,799,759**
	Less:					
47	Sales for Resale		0	0	0	0
48	Other Revenues		9,099,243	0	0	9,099,243
49	Billing Credits		0	0	0	0
50	**Total Operating Expenses**		**$305,824,770**	**$259,274,953**	**$72,604**	**$46,477,212**
51	**Return from Rate Base Schedule 1**		**$20,453,973**	**$4,205,080**	**$1,133,748**	**$15,115,146**
52	**Total Cost**		**$326,278,743**	**$263,480,033**	**$1,206,352**	**$61,592,358**

Clark Public Utilties

Residential Purchase and Sale Agreement
COOKBOOK
Jurisdiction: Clark Public Utilities

Test Period: October 1, 2005 - September 31, 2006
BPA Docket Number: Run No. 12 10-6-05 Base Case
All Taxes
Dollars in units

Line Number	Account Decription	Total to be Functionalized	Functionalized Amount Production	Transmisison	Distribution
1	Fed Tax-Insurance Contrib.	0	0	0	0
2	Fed Tax-Unemployment	0	0	0	0
3	In-lieu Tax	18,778,677	14,910,021	68,897	3,799,759
4	Other Taxes	0	0	0	0
5	Federal Income Tax	0	0	0	0
6	Total Deferred Taxes	0	0	0	0
7	Miscellaneous Taxes	0	0	0	0
	Washington				
8	State Income Taxes	0	0	0	0
9	State Property Tax	0	0	0	0
10	State Unemp. Tax	0	0	0	0
11	State Reg. Commis. Tax	0	0	0	0
12	State Generating Tax	0	0	0	0
13	State Pollution Control Tax	0	0	0	0
14	State Revenue and Business Tax	0	0	0	0
15	Local Occupation and Franchise Tax	0	0	0	0
16	Misc Taxes	0	0	0	0
17	Other Tax Item	0	0	0	0
18	Other Tax Item	0	0	0	0
	State Two (Put Name Here)				
19	State Income Taxes	0	0	0	0
20	State Property Tax	0	0	0	0
21	State Unemp. Tax	0	0	0	0
22	State Reg. Commis. Tax	0	0	0	0
23	State Generating Tax	0	0	0	0
24	State Pollution Control Tax	0	0	0	0
25	State Rev. & Business Tax	0	0	0	0
26	Local Occupation & Franchise	0	0	0	0
27	Other Tax Item	0	0	0	0
28	Other Tax Item	0	0	0	0
29	Other Tax Item	0	0	0	0
30	**Total Taxes**	$18,778,677	$14,910,021	$68,897	$3,799,759

Clark Public Utilties

Residential Purchase and Sale Agreement
COOKBOOK
Jurisdiction: Clark Public Utilities

Test Period: October 1, 2005 - September 31, 2006
BPA Docket Number: Run No. 12 10-6-05 Base Case
Other Included Items
Dollars in units

Line Number	Account Decription	Total to be Functionalized	Functionalized Amount Production	Transmisison	Distribution
1	Gain from Disp. of Plant 411.6	0	0	0	0
2	Loss from Disp. of Plant 411.7	0	0	0	0
3	**Total Disp. of Plant**	**0**	**0**	**0**	**0**
	Sale from Resale:				
4	Nonfirm Sales for Resale 447	0	0	0	0
5	Firm Sales For Resale 447	0	0	0	0
6	**Total Sales from Resale**	**0**	**0**	**0**	**0**
	Other Revenues:				
7	Forfeited Discounts 450	0	0	0	0
8	Miscellaneous Service Revenues 451	7,768,165	0	0	7,768,165
9	Sales of water/water power 453	0	0	0	0
10	Rent from property 454	0	0	0	0
11	Interdepartmental Rents 455	0	0	0	0
12	Other electric revenues 456	0	0	0	0
13	Billing Credits	0	0	0	0
14	Other Revenue Acct. No.	776,928	0	0	776,928
15	Other Revenue Acct. No.	554,150	0	0	554,150
16	**Total Other Revenues**	**9,099,243**	**0**	**0**	**9,099,243**
17	**Total Other Included Items**	**$9,099,243**	**$0**	**$0**	**$9,099,243**

Clark Public Utilties

Residential Purchase and Sale Agreement
COOKBOOK
Jurisdiction: Clark Public Utilities

Test Period: October 1, 2005 - September 31, 2006
BPA Docket Number: Run No. 12 10-6-05 Base Case
Average System Cost
Dollars in units

Line Number	Account Decription		Amount
	Contract System Costs		
1		Production Cost	263,480,033
2		Transmission Cost	1,206,352
3		Less Excluded Costs	0
4	**Total Contract System Costs**		**264,686,385**
	Contract System Load		
6		Total Load (kWh)	4,647,967,387
	Less:		
7		Non-firm Adjustments (kWh)	0
8		Other Adjustments (kWh)	0
9	**Net Load**		**4,647,967,387**
	Plus:		
10		Distribution Losses (kWh)	0
11	**Total Net Load**		**4,647,967,387**
	Less:		
12		Excluded Load (kWh)	0
13		Excl. Load Dist. Losses (kWh)	161,585,926
14	**Total Contract System Load**		**4,486,381,461**
15	**Average System Cost (mills/kWh)**		**59.00**

Clark Public Utilties
Residential Purchase and Sale Agreement
COOKBOOK
Jurisdiction: Clark Public Utilities

Test Period: October 1, 2005 - September 31, 2006
BPA Docket Number: Run No. 12 10-6-05 Base Case
Dollars in units

Line Number	Account Decription		Total to be Functionalized	Functionalized Amount Production	Transmisison	Distribution
	General Plant: 389-399					
1	Land and Land Rights	389	489,152	0	22,008	467,144
2	Land and Land Rights	389	0	0	0	0
3	Structures and Improvements	390	18,389,177	0	827,374	17,561,803
4	Structures and Improvements	390	0	0	0	0
5	Furniture and Equipment	391	7,387,614	153,368	1,317	7,232,928
6	Furniture and Equipment	391	0	0	0	0
7	Transportation Equipment	392	8,472,587	0	381,202	8,091,385
8	Transportation Equipment	392	0	0	0	0
9	Stores Equipment	393	313,215	0	14,092	299,123
10	Tools and Garage Equipment	394	934,984	0	42,067	892,917
11	Laboratory Equipment	395	344,589	0	15,504	329,085
12	Power Operated Equipment	396	389,289	0	17,515	371,774
13	Communication Equipment	397	1,574,497	0	70,840	1,503,657
14	Miscellaneous Equipment	398	957,429	0	0	957,429
15	Other Tangible Property	399	10,847	0	488	10,359
16	**Total General Plant 389-399**		**39,263,380**	**153,368**	**1,392,409**	**37,717,603**
	Labor Ratio Input:					
17	Production	500-507	390,044	390,044	0	0
18	Transmission	560-573	3,350	0	3,350	0
19	Distribution	580-598	4,346,429	0	0	4,346,429
20	Customer Account	901-905	4,723,188	0	0	4,723,188
21	Customer Service	907-910	51,072	0	0	51,072
22	Sales Expense	911-916	0	0	0	0
23	Admin. & General	920-932	9,273,993	0	0	9,273,993
24	Other Labor	Acct. No.	0	0	0	0
25	Other Labor	Acct. No.	0	0	0	0
26	**Total Labor**		**18,788,076**	**390,044**	**3,350**	**18,394,682**

Clark Public Utilties

Residential Purchase and Sale Agreement
COOKBOOK
Jurisdiction: Clark Public Utilities

Test Period: October 1, 2005 - September 31, 2006
BPA Docket Number: Run No. 12 10-6-05 Base Case
Cash Working Capital
Dollars in units

Line Number	Account Decription	Total to be Functionalized	Functionalized Amount Production	Transmisison	Distribution
1	Total Production O&M	243,949,602	243,949,602	0	0
2	Total Transmission O&M	0	0	0	0
3	Total Distribution O&M	8,575,874	0	0	8,575,874
4	Customer Accounting Expense	9,060,844	0	0	9,060,844
5	Customer Service Expense	1,221,898	0	0	1,221,898
6	Sales Expense	0	0	0	0
7	Total Administrative and General O&M	15,062,139	415,330	3,708	14,643,102
8	Less Purchased Power and Fuel Costs	(243,949,602)	(243,949,602)	0	0
9	One Eighth O&M Expenses (Less Purch. Power and Fuel Costs)	4,240,094	51,916	463	4,187,715
10	Difference from Filing	(4,240,094)	0	0	(4,240,094)
11	Allowable Functionalized Cash Working Capital	**$4,240,094**	**$51,916**	**$51,916**	**$4,187,715**

* Any amount of Purchase Power that is included in the calculation of Cash Working Capital is functionalized to Distribution.

Clark Public Utilties

Residential Purchase and Sale Agreement
COOKBOOK
Jurisdiction: Clark Public Utilities

Test Period: October 1, 2005 - September 31, 2006
BPA Docket Number: Run No. 12 10-6-05 Base Case
In Lieu Tax
Dollars in units

Line Number	Account Decription	Total to be Functionalized	Functionalized Amount Production	Transmisison	Distribution
1	Net Plant Amounts (from "As Filed" Data Matrix)	261,739,508	42,686	19,392,479	242,304,343
2	Tax Rates	Low	High		
3		0.0%	0.0%		
4	In-lieu Tax (from "As Filed" Data Matrix)	18,778,677	14,910,021	68,897	3,799,759
5	In Lieu Tax Cap (calculated)	0			
6	Lessor of In Lieu Tax and In Lieu Tax Cap	0			
7	Direct Analysis: (Net Plant * Applicable Tax Rate)	0	0	0	0
8	Percentage Calculation	0.0%	0.0%	0.0%	0.0%
9	Functionalized In Lieu Tax	**18,778,677**	**14,910,021**	**68,897**	**3,799,759**

Appendix 1	**Clark Public Utilties**					Schedule 1
Page 1	Residential Purchase and Sale Agreement					Page 1 of 2
	AS FILED					
	Jurisdiction: Clark Public Utilities					
	Test Period: October 1, 2005 - September 31, 2006					
	BPA Docket Number: Run No. 12 10-6-05 Base Case					
	Plant Investment/Rate Base/Rate of Return					
	Dollars in units					

Line Number	Account Decription		Total to be Functionalized	Functionalized Amount Production	Transmisison	Distribution
	Production Plant:					
1	Steam Production	310-316	0	0	0	0
2	Nuclear Production	320-325	0	0	0	0
3	Hydraulic Production	330-336	0	0	0	0
4	Other Production	340-346	0	0	0	0
5	Other Production	340-346	0	0	0	0
6	Other Production	340-346	0	0	0	0
7	Other Production	340-346	0	0	0	0
8	**Total Production Plant**		**0**	**0**	**0**	**0**
9	Transmission Plant	350-359	19,168,781	0	19,168,781	0
10	Other Transmission	Acct. No.	0	0	0	0
11	Other Transmission	Acct. No.	0	0	0	0
12	**Total Transmission Plant 350-359**		**19168781**	**0**	**19168781**	**0**
13	**Total Distribution Plant 360-373**		406,875,687	0	0	406,875,687
14	**Intangible Plant 301**		3,601,776	0	162,053	3,439,723
15	**Total General Plant 389-399**		39,263,380	153,368	1,392,409	37,717,603
16	**Total Electric Plant In-Service**		**465,323,271**	**153,368**	**20,561,884**	**444,608,019**
	Less - Depreciation and Amortization:					
17	Steam Plant	108	0	0	0	0
18	Nuclear Plant	108	0	0	0	0
19	Hydraulic Plant	108	0	0	0	0
20	Other Production Plant	108	0	0	0	0
21	Intangible Plant	108	0	0	0	0
22	Transmission Plant	108	0	0	0	0
23	Distribution Plant	108	171,591,355	0	0	171,591,355
24	General Plant	108	28,335,340	110,682	1,004,865	27,219,794
25	Other Amortization	Acct. No.	0	0	0	0
26	Amort. Reserve	111	3,657,068	0	164,540	3,492,528
27	**Total Depreciation and Amortization**		**203,583,763**	**110,682**	**1,169,405**	**202,303,676**
28	**Total Net Electric Plant In-Service**		**$261,739,508**	**$42,686**	**$19,392,479**	**$242,304,343**

Clark Public Utilties
Residential Purchase and Sale Agreement
AS FILED
Jurisdiction: Clark Public Utilities

Test Period: October 1, 2005 - September 31, 2006
BPA Docket Number: Run No. 12 10-6-05 Base Case
Plant Investment/Rate Base/Rate of Return
Dollars in units

Line Number	Account Decription		Total to be Functionalized	Production	Transmisison	Distribution
				Functionalized Amount		
	Add - Debits:					
29	Cash Working Capital		0	51,916	463	(52,380)
30	Plant Held Future Use 105		0	0	0	0
31	Completed Construction 106		0	0	0	0
32	CWIP 107-120.1		13,821,782	0	0	13,821,782
33	Acquisitions Adjustments 114		0	0	0	0
34	Nuclear Fuel 120.2-120.4		0	0	0	0
35	Investments 123		0	0	0	0
36	Other Investment 124		0	0	0	0
37	Weatherization Investment		301,904	301,904	0	0
38	Fuel Stock 151-152		0	0	0	0
39	Materials and Supplies 153-157,163		2,367,062	0	104,645	2,262,417
40	Clearing Accounts 184		0	0	0	0
41	Misc. Deferred Debits 186		72,518,691	72,518,691	0	0
42	Other Debits 182		0	0	0	0
43	Prepayments 165		332,290	0	0	332,290
44	**Total Debits**		**89,341,729**	**72,872,511**	**105,109**	**16,364,109**
	Less - Credits:					
45	Cust. Advances for Const. 252		0	0	0	0
46	Other Deferred Credits 253		0	0	0	0
47	Accum Def. Inv. Tax Credit 255		0	0	0	0
48	Deferred Gain - Disposition 256		0	0	0	0
49	Unamortized Gain - Reacq. 257		0	0	0	0
50	Accum. Def. Income Taxes 281-283		0	0	0	0
51	Other Credits Acct. No.		0	0	0	0
52	Other Credits Acct. No.		0	0	0	0
53	**Total Credits**		**0**	**0**	**0**	**0**
54	**Total Rate Base**		**$351,081,237**	**$72,915,198**	**$19,497,588**	**$258,668,452**
	Rate of Return:	**5.77%**				
55	**Return from Rate Base**		**$20,247,145**	**$4,205,080**	**$1,124,442**	**$14,917,624**

Appendix 1	Clark Public Utilties					Schedule 3
Page 3	Residential Purchase and Sale Agreement					Page 1 of 2
	AS FILED					
	Jurisdiction: Clark Public Utilities					
	Test Period: October 1, 2005 - September 31, 2006					
	BPA Docket Number: Run No. 12 10-6-05 Base Case					
	Expenses					
	Dollars in units					

Line Number	Account Decription		Total to be Functionalized	Production	Functionalized Amount Transmisison	Distribution
	Production Expense:					
1	Fuel 501,518,547		0	0	0	0
2	Purchased Power 555		243,949,602	243,949,602	0	0
	Operations and Maintenance:					
3	Steam 500, 502-14		0	0	0	0
4	Nuclear 517, 519-32		0	0	0	0
5	Hydro 535-45		0	0	0	0
6	Other 546, 548-54, 556-57		0	0	0	0
7	**Total Production Expense**		**243,949,602**	**243,949,602**	**0**	**0**
8	Transmission 560-73		0	0	0	0
9	Distribution 580-98		8,575,874	0	0	8,575,874
10	Customer Accounting Expense 901-905		9,060,844	0	0	9,060,844
11	Customer Service Expense 907-910		1,221,898	0	0	1,221,898
12	Sales Expense 911-916		0	0	0	0
	Administration and General Expense:					
13	Adm. and General Salaries 920		8,419,521	174,791	1,501	8,243,229
14	Office supplies & expenses 921		2,626,441	54,525	468	2,571,447
15	Adm. expenses transfer- Cr. 922		(861,320)	(17,881)	(154)	(843,285)
16	Outside services employed 923		3,291,705	68,336	587	3,222,782
17	Property insurance 924		23,737	8	1,049	22,680
18	Injuries and damages 925		0	0	0	0
19	Emp. pensions & benefits 926		260,665	5,411	46	255,207
20	Franchise requirements 927		0	0	0	0
21	Regulatory Comm. Exp. 928		0	0	0	0
22	Duplicate charges-credit 929		0	0	0	0
23	General advertising Exp. 930.1		0	0	0	0
24	Misc. general expenses 930.2	DIR-D :: DIR-D	1,301,390	130,139	209	1,171,042
25	Rents 931		0	0	0	0
26	Maint. of general plant 932		0	0	0	0
27	Other A&G Acct. No.		0	0	0	0
28	Other A&G Acct. No.		0	0	0	0
29	**Total A&G Expense**		**15,062,139**	**415,330**	**3,708**	**14,643,102**
30	**Total Operations and Maintenance**		**$277,870,357**	**$244,364,932**	**$3,708**	**$33,501,718**

Appendix 1		Clark Public Utilties				Schedule 3
Page 4		Residential Purchase and Sale Agreement				Page 2 of 2
		AS FILED				
		Jurisdiction: Clark Public Utilities				
		Test Period: October 1, 2005 - September 31, 2006				
		BPA Docket Number: Run No. 12 10-6-05 Base Case				
		Expenses				
		Dollars in units				

Line Number	Account Decription		Total to be Functionalized	Functionalized Amount Production	Transmisison	Distribution
	Depreciation and Amortization:					
31		Steam - Depreciation Exp. 403	0	0	0	0
32		Nuclear - Depreciation Exp. 403	0	0	0	0
33		Hydro. - Depreciation Exp. 403	0	0	0	0
34		Other Prod. - Depreciation 403	0	0	0	0
35		Trans. - Depreciation Exp. 403	0	0	0	0
36		Distr. - Depreciation Exp. 403	18,274,979	0	0	18,274,979
37		Gen. Plant - Depreciation 403	0	0	0	0
38		Other Depreciation Exp. 404	0	0	0	0
39		Amortization 404	0	0	0	0
40		Other Amort. Acct. No.	0	0	0	0
41		Other Amort. Acct. No.	0	0	0	0
42	**Total Depreciation and Amortization**		18,274,979	0	0	18,274,979
	Add:					
43		Taxes Other Than Income Taxes	18,778,677	14,910,021	68,897	3,799,759
44		Federal Income Taxes	0	0	0	0
45		State Income Taxes	0	0	0	0
46	**Total Taxes**		18,778,677	14,910,021	68,897	3,799,759
	Less:					
47		Sales for Resale	0	0	0	0
48		Other Revenues	9,099,243	0	0	9,099,243
49		Billing Credits	0	0	0	0
50	**Total Operating Expenses**		$305,824,770	$259,274,953	$72,604	$46,477,212
51	**Return from Rate Base Schedule 1**		$20,247,145	$4,205,080	$1,124,442	$14,917,624
52	**Total Cost**		$326,071,915	$263,480,033	$1,197,046	$61,394,836

Appendix 1	Clark Public Utilties	Schedule 3A
Page 5	Residential Purchase and Sale Agreement	Page 1 of 1
	AS FILED	
	Jurisdiction: Clark Public Utilities	
	Test Period: October 1, 2005 - September 31, 2006	
	BPA Docket Number: Run No. 12 10-6-05 Base Case	
	All Taxes	
	Dollars in units	

Line Number	Account Decription	Total to be Functionalized	Functionalized Amount Production	Transmisison	Distribution
1	Fed Tax-Insurance Contrib.	0	0	0	0
2	Fed Tax-Unemployment	0	0	0	0
3	In-lieu Tax	18,778,677	14,910,021	68,897	3,799,759
4	Other Taxes	0	0	0	0
5	Federal Income Tax	0	0	0	0
6	Total Deferred Taxes	0	0	0	0
7	Miscellaneous Taxes	0	0	0	0
	Washington				
8	State Income Taxes	0	0	0	0
9	State Property Tax	0	0	0	0
10	State Unemp. Tax	0	0	0	0
11	State Reg. Commis. Tax	0	0	0	0
12	State Generating Tax	0	0	0	0
13	State Pollution Control Tax	0	0	0	0
14	State Revenue and Business Tax	0	0	0	0
15	Local Occupation and Franchise Tax	0	0	0	0
16	Misc Taxes	0	0	0	0
17	Other Tax Item	0	0	0	0
18	Other Tax Item	0	0	0	0
	State Two (Put Name Here)				
19	State Income Taxes	0	0	0	0
20	State Property Tax	0	0	0	0
21	State Unemp. Tax	0	0	0	0
22	State Reg. Commis. Tax	0	0	0	0
23	State Generating Tax	0	0	0	0
24	State Pollution Control Tax	0	0	0	0
25	State Rev. & Business Tax	0	0	0	0
26	Local Occupation & Franchise	0	0	0	0
27	Other Tax Item	0	0	0	0
28	Other Tax Item	0	0	0	0
29	Other Tax Item	0	0	0	0
30	**Total Taxes**	**$18,778,677**	**$14,910,021**	**$68,897**	**$3,799,759**

Appendix 1	Clark Public Utilties				Schedule 3B
Page 6	Residential Purchase and Sale Agreement				Page 1 of 1
	AS FILED				
	Jurisdiction: Clark Public Utilities				
	Test Period: October 1, 2005 - September 31, 2006				
	BPA Docket Number: Run No. 12 10-6-05 Base Case				
	Other Included Items				
	Dollars in units				

Line Number	Account Decription	Total to be Functionalized	Functionalized Amount Production	Transmisison	Distribution
1	Gain from Disp. of Plant 411.6	0	0	0	0
2	Loss from Disp. of Plant 411.7	0	0	0	0
3	**Total Disp. of Plant**	**0**	**0**	**0**	**0**
	Sale from Resale:				
4	Nonfirm Sales for Resale 447	0	0	0	0
5	Firm Sales For Resale 447	0	0	0	0
6	**Total Sales from Resale**	**0**	**0**	**0**	**0**
	Other Revenues:				
7	Forfeited Discounts 450	0	0	0	0
8	Miscellaneous Service Revenues 451	7,768,165	0	0	7,768,165
9	Sales of water/water power 453	0	0	0	0
10	Rent from property 454	0	0	0	0
11	Interdepartmental Rents 455	0	0	0	0
12	Other electric revenues 456	0	0	0	0
13	Billing Credits	0	0	0	0
14	Other Revenue Acct. No.	776,928	0	0	776,928
15	Other Revenue Acct. No.	554,150	0	0	554,150
16	**Total Other Revenues**	**9,099,243**	**0**	**0**	**9,099,243**
17	**Total Other Included Items**	**$9,099,243**	**$0**	**$0**	**$9,099,243**

Clark Public Utilties

Residential Purchase and Sale Agreement
AS FILED
Jurisdiction: Clark Public Utilities

Test Period: October 1, 2005 - September 31, 2006
BPA Docket Number: Run No. 12 10-6-05 Base Case
Average System Cost
Dollars in units

Line Number	Account Decription	Amount
	Contract System Costs	
1	Production Cost	263,480,033
2	Transmission Cost	1,197,046
3	Less Excluded Costs	0
4	**Total Contract System Costs**	264,677,079
	Contract System Load	
6	Total Load (kWh)	4,647,967,387
	Less:	
7	Non-firm Adjustments (kWh)	0
8	Other Adjustments (kWh)	0
9	**Net Load**	4,647,967,387
	Plus:	
10	Distribution Losses (kWh)	0
11	**Total Net Load**	4,647,967,387
	Less:	
12	Excluded Load (kWh)	0
13	Excl. Load Dist. Losses (kWh)	161,585,926
14	**Total Contract System Load**	4,486,381,461
15	**Average System Cost (mills/kWh)**	59.00

Clark Public Utilties

Residential Purchase and Sale Agreement

AS FILED

Jurisdiction: Clark Public Utilities

Test Period: October 1, 2005 - September 31, 2006

BPA Docket Number: Run No. 12 10-6-05 Base Case

Dollars in units

Line Number	Account Decription	Total to be Functionalized	Production	Transmisison	Distribution
			Functionalized Amount		
	General Plant: 389-399				
1	Land and Land Rights 389	489,152	0	22,008	467,144
2	Land and Land Rights 389	0	0	0	0
3	Structures and Improvements 390	18,389,177	0	827,374	17,561,803
4	Structures and Improvements 390	0	0	0	0
5	Furniture and Equipment 391	7,387,614	153,368	1,317	7,232,928
6	Furniture and Equipment 391	0	0	0	0
7	Transportation Equipment 392	8,472,587	0	381,202	8,091,385
8	Transportation Equipment 392	0	0	0	0
9	Stores Equipment 393	313,215	0	14,092	299,123
10	Tools and Garage Equipment 394	934,984	0	42,067	892,917
11	Laboratory Equipment 395	344,589	0	15,504	329,085
12	Power Operated Equipment 396	389,289	0	17,515	371,774
13	Communication Equipment 397	1,574,497	0	70,840	1,503,657
14	Miscellaneous Equipment 398	957,429	0	0	957,429
15	Other Tangible Property 399	10,847	0	488	10,359
16	**Total General Plant 389-399**	**39,263,380**	**153,368**	**1,392,409**	**37,717,603**
	Labor Ratio Input:				
17	Production 500-507	390,044	390,044	0	0
18	Transmission 560-573	3,350	0	3,350	0
19	Distribution 580-598	4,346,429	0	0	4,346,429
20	Customer Account 901-905	4,723,188	0	0	4,723,188
21	Customer Service 907-910	51,072	0	0	51,072
22	Sales Expense 911-916	0	0	0	0
23	Admin. & General 920-932	9,273,993	0	0	9,273,993
24	Other Labor Acct. No.	0	0	0	0
25	Other Labor Acct. No.	0	0	0	0
26	**Total Labor**	**18,788,076**	**390,044**	**3,350**	**18,394,682**

Total Transmission	$0	$0				
Distribution						
Op. Supervision & Engineering	$0	64,095	16,024	69,010	51,758	67,781
Load Dispatching	$0	-	-		-	-
Line and Station Expenses	$0	2,773,879	30,433	2,986,602	2,239,952	2,270,384
Station Expenses	$0	121,730	693,470	131,065	98,299	791,769
Underground Lines	$0	4,800	1,200	5,168	3,876	5,076
Street Lighting & Signal System	$0	-	-		-	-
Meters	$0	80,550	20,138	86,727	65,045	85,183
Customer Installations	$0	1,006,588	251,647	1,083,781	812,836	1,064,483
Misc. Distribution	$0	273,214	68,304	294,166	220,625	288,928
Rents	$0	-	-		-	-
Maint. Supervision & Engineering	$0	70,675	17,669	76,095	57,071	74,740
Maint. of Structures	$0		-		-	-
Maint. of Station Equipment	$0	2,921,988	730,497	3,146,069	2,359,552	3,090,049
Maint. of Structures and Equipment	$0		-		-	-
Maint. of Overhead Lines	$0	276,000	69,000	297,166	222,875	291,875
Maint. Of Underground Lines	$0	-	-		-	-
Maint. of Lines	$0	-	-		-	-
Maint. of Line Transformers	$0	-	-		-	-
Maint. of Street Lighting & Signal System	$0	420,396	105,099	452,635	339,476	444,575
Maint. of Meters	$0	-	-		-	-
Maint. of Misc. Distribution Plant	$0	-	-		-	-
Other	$0		-		-	-
Other	$0		-		-	-
Other	$0		-		-	-
Total Distribution	$0	$8,013,915	$2,003,479	$8,628,484		
Other			-			
Other			-			
Other			-			
Other			-			
Other			-			
Total Other	$0	$0				
Total Operation & Maintenance	$0	$8,013,915	$2,003,479			

Customer Service, Accounts, & Sales						
Supervision	$0	1,600	400			
Meter Reading	$0	96,748	24,187	104,167	78,125	102,312
Customer Records Collection	$0	6,162,027	1,540,507	6,634,580	4,975,935	6,516,442
Uncollectable Accounts	$0	2,208,333	552,083	2,377,685	1,783,264	2,335,347
Misc. Customer Accounts	$0	60,000	15,000	64,601	48,451	63,451
Customer Service & Information	$0				-	-
Customer Communication & Education	$0	1,080,230		1,164,793	873,595	873,595
Customer Assistance	$0	-			-	-
Misc. Customer Service & Information	$0				-	-
Demonstrating & Selling	$0				-	-
Advertising	$0				-	-
Misc. Sales Expenses	$0				-	-
Sales Expenses	$0				-	-
Other	$0				-	-
Other	$0				-	-
Other	$0				-	-
Total Customer Service, Accounts & Sales	$0	$9,608,938	$2,132,177			
Total O&M w/o Purchased Power Supply & A&G	$0	$17,622,853	$4,135,656			
Administrative & General						
Administrative & General Salaries	$0	7,867,809	1,966,952	8,471,175	6,353,381	8,320,334
Office Supplies	$0	2,454,336	613,584	2,642,554	1,981,916	2,595,500
Administrative Transfer - Credit	$0	(804,880)	(201,220)	(866,605)	(649,954)	(851,174)
Outside Services	$0	3,076,007	769,002	3,311,900	2,483,925	3,252,927
Property Insurance	$0	22,182	5,546	23,883	17,912	23,458
Injuries and Damages	$0	-	-		-	-
Employee Pension & Benefits	$0	243,584	60,896	262,264	196,698	257,594
Franchise Requirements	$0		-		-	-
Regulatory Expense	$0		-		-	-
Duplicate Charge - Credit	$0		-		-	-
General Advertising	$0		-		-	-
Misc. General Expense	$0		-		-	-
Rents	$0		-		-	-
Maint. of Structures and Equipment	$0	494,155	123,539	1,309,374	982,031	1,105,569

Transportation	$0		-		-	-
Other	$0		-		-	-
Other	$0		-		-	-
Other	$0		-		-	-
Total Administrative & General	$0	$13,353,193	$3,338,298			
Total O&M plus A&G	$0	$30,976,046	$7,473,954			
Depreciation						
Generation Plant			-			-
Transmission Plant			-			-
Distribution Plant			-			-
General Plant			-			-
Other			-			-
Other			-			-
Total Depreciation	$0					
Taxes						
Property Tax						
Taxes						
State Excise Tax - 3.873%	$0					
State Privilege Tax - 2.14%	$0					
Taxes on Miscellaneous Revenues	$0					
Other						
Total Taxes	$0	$0	$0			
Interest and Debt Service Expense						
Interest on Long-Term Debt						
Amortization of Debt Discount						
Other Interest Expense						
Annual LT Debt Service		$30,780,944	7,695,236	$30,780,944		$30,780,944
Annual ST Debt Service						
BAN Proceeds Acquisition Fund						
Miscellaneous Expenses						
Total Interest / Debt Service Expense	$0	$30,780,944	$7,695,236			
Return on Investment						
Production Plant	$0					
Transmission Plant	$0					

Distribution Plant	$0					
Other	$0					
Total Return on Investment	$0					
Capital Projects Funded From Rates						
Production						
Transmission	$774,274	$774,274	193,568	811,133	608,350	801,918
Distribution	$6,046,234	$6,046,234	1,511,558	6,334,064	4,750,548	6,262,107
General	$1,205,336	$1,205,336	301,334	1,262,716	947,037	1,248,371
Other						
Other						
Total Capital Projects Funded From Rates	$8,025,843	$8,025,843	$2,006,461	8,407,913	6,305,935	8,312,396
Other Contributions						
Operating Reserve						
Rate Stabilization Account						
Debt Service Coverage Requirement						
Non-Operating Expenses/Margins	$0					
Donations						
Credits and Dividends						
Conservation Expense	$0					
Total Other Contributions	$0					
Revenue Requirement Before Other Revenues	$8,025,843					
Revenue Req. Before Taxes and Other Revenues	$8,025,843					
Other Revenues						
Forfeited Deposits						
Misc. Service Revenues						
Rent						
Miscellaneous Revenue (Other)	$0	$7,080,339	$1,770,085			
Transfer Credits						
Internet Set Up & Fees						
Dividends from Affiliates						
Other Revenue						
Other Revenue						
Rate Stabilization Account						
Conservation		$200,000	50,000			

Investment Income		$551,000	137,750
Total Other Revenues	$0		
REVENUE REQUIREMENT for COST ALLOCATION	$8,025,843		

Clark Public Utilties

Residential Purchase and Sale Agreement
FINAL REPORT
Jurisdiction: Clark Public Utilities

Test Period: October 1, 2005 - September 31, 2006
BPA Docket Number: Run No. 12 10-6-05 Base Case
Plant Investment/Rate Base/Rate of Return
Dollars in units

Line Number	Account Decription		Total to be Functionalized	Functionalized Amount Production	Transmisison	Distribution
	Production Plant:					
1	Steam Production	310-316	0	0	0	0
2	Nuclear Production	320-325	0	0	0	0
3	Hydraulic Production	330-336	0	0	0	0
4	Other Production	340-346	0	0	0	0
5	Other Production	340-346	0	0	0	0
6	Other Production	340-346	0	0	0	0
7	Other Production	340-346	0	0	0	0
8	**Total Production Plant**		0	0	0	0
9	Transmission Plant	350-359	19,168,781	0	19,168,781	0
10	Other Transmission	Acct. No.	0	0	0	0
11	Other Transmission	Acct. No.	0	0	0	0
12	**Total Transmission Plant 350-359**		19,168,781	0	19,168,781	0
13	**Total Distribution Plant 360-373**		406,875,687	0	0	406,875,687
14	**Intangible Plant 301**		3,601,776	0	162,053	3,439,723
15	**Total General Plant 389-399**		39,263,380	153,368	1,392,409	37,717,603
16	**Total Electric Plant In-Service**		465,323,271	153,368	20,561,884	444,608,019
	Less - Depreciation and Amortization:					
17	Steam Plant	108	0	0	0	0
18	Nuclear Plant	108	0	0	0	0
19	Hydraulic Plant	108	0	0	0	0
20	Other Production Plant	108	0	0	0	0
21	Intangible Plant	108	0	0	0	0
22	Transmission Plant	108	0	0	0	0
23	Distribution Plant	108	171,591,355	0	0	171,591,355
24	General Plant	108	28,335,340	110,682	1,004,865	27,219,794
25	Other Amortization	Acct. No.	0	0	0	0
26	Amort. Reserve	111	3,657,068	0	164,540	3,492,528
27	**Total Depreciation and Amortization**		203,583,763	110,682	1,169,405	202,303,676
28	**Total Net Electric Plant In-Service**		$261,739,508	$42,686	$19,392,479	$242,304,343

Clark Public Utilties
Residential Purchase and Sale Agreement
FINAL REPORT
Jurisdiction: Clark Public Utilities

Test Period: October 1, 2005 - September 31, 2006
BPA Docket Number: Run No. 12 10-6-05 Base Case
Plant Investment/Rate Base/Rate of Return
Dollars in units

Line Number	Account Decription	Total to be Functionalized	Functionalized Amount: Production	Transmisison	Distribution
	Add - Debits:				
29	Cash Working Capital	0	51,916	463	(52,380)
30	Plant Held Future Use 105	0	0	0	0
31	Completed Construction 106	0	0	0	0
32	CWIP 107-120.1	13,821,782	0	0	13,821,782
33	Acquisitions Adjustments 114	0	0	0	0
34	Nuclear Fuel 120.2-120.4	0	0	0	0
35	Investments 123	0	0	0	0
36	Other Investment 124	0	0	0	0
37	Weatherization Investment	301,904	301,904	0	0
38	Fuel Stock 151-152	0	0	0	0
39	Materials and Supplies 153-157,163	2,367,062	0	104,645	2,262,417
40	Clearing Accounts 184	0	0	0	0
41	Misc. Deferred Debits 186	72,518,691	72,518,691	0	0
42	Other Debits 182	0	0	0	0
43	Prepayments 165	332,290	0	0	332,290
44	**Total Debits**	**89,341,729**	**72,872,511**	**105,109**	**16,364,109**
	Less - Credits:				
45	Cust. Advances for Const. 252	0	0	0	0
46	Other Deferred Credits 253	0	0	0	0
47	Accum Def. Inv. Tax Credit 255	0	0	0	0
48	Deferred Gain - Disposition 256	0	0	0	0
49	Unamortized Gain - Reacq. 257	0	0	0	0
50	Accum. Def. Income Taxes 281-283	0	0	0	0
51	Other Credits Acct. No.	0	0	0	0
52	Other Credits Acct. No.	0	0	0	0
53	**Total Credits**	**0**	**0**	**0**	**0**
54	**Total Rate Base**	**$351,081,237**	**$72,915,198**	**$19,497,588**	**$258,668,452**
	Rate of Return: 5.77%				
55	**Return from Rate Base**	**$20,247,145**	**$4,205,080**	**$1,124,442**	**$14,917,624**

Clark Public Utilties
Residential Purchase and Sale Agreement
FINAL REPORT
Jurisdiction: Clark Public Utilities

Test Period: October 1, 2005 - September 31, 2006
BPA Docket Number: Run No. 12 10-6-05 Base Case
Expenses
Dollars in units

Line Number	Account Decription		Total to be Functionalized	Functionalized Amount Production	Transmisison	Distribution
	Production Expense:					
1	Fuel	501,518,547	0	0	0	0
2	Purchased Power	555	243,949,602	243,949,602	0	0
	Operations and Maintenance:					
3	Steam	500, 502-14	0	0	0	0
4	Nuclear	517, 519-32	0	0	0	0
5	Hydro	535-45	0	0	0	0
6	Other	546, 548-54, 556-57	0	0	0	0
7	**Total Production Expense**		**243,949,602**	**243,949,602**	**0**	**0**
8	Transmission	560-73	0	0	0	0
9	Distribution	580-98	8,575,874	0	0	8,575,874
10	Customer Accounting Expense	901-905	9,060,844	0	0	9,060,844
11	Customer Service Expense	907-910	1,221,898	0	0	1,221,898
12	Sales Expense	911-916	0	0	0	0
	Administration and General Expense:					
13	Adm. and General Salaries	920	8,419,521	174,791	1,501	8,243,229
14	Office supplies & expenses	921	2,626,441	54,525	468	2,571,447
15	Adm. expenses transfer- Cr.	922	(861,320)	(17,881)	(154)	(843,285)
16	Outside services employed	923	3,291,705	68,336	587	3,222,782
17	Property insurance	924	23,737	8	1,049	22,680
18	Injuries and damages	925	0	0	0	0
19	Emp. pensions & benefits	926	260,665	5,411	46	255,207
20	Franchise requirements	927	0	0	0	0
21	Regulatory Comm. Exp.	928	0	0	0	0
22	Duplicate charges-credit	929	0	0	0	0
23	General advertising Exp.	930.1	0	0	0	0
24	Misc. general expenses	930.2	1,301,390	130,139	209	1,171,042
25	Rents	931	0	0	0	0
26	Maint. of general plant	932	0	0	0	0
27	Other A&G	Acct. No.	0	0	0	0
28	Other A&G	Acct. No.	0	0	0	0
29	**Total A&G Expense**		**15,062,139**	**415,330**	**3,708**	**14,643,102**
30	**Total Operations and Maintenance**		**$277,870,357**	**$244,364,932**	**$3,708**	**$33,501,718**

Clark Public Utilties

Residential Purchase and Sale Agreement
FINAL REPORT
Jurisdiction: Clark Public Utilities

Test Period: October 1, 2005 - September 31, 2006
BPA Docket Number: Run No. 12 10-6-05 Base Case
Expenses
Dollars in units

Line Number	Account Decription		Total to be Functionalized	Functionalized Amount Production	Transmisison	Distribution
	Depreciation and Amortization:					
31	Steam - Depreciation Exp.	403	0	0	0	0
32	Nuclear - Depreciation Exp.	403	0	0	0	0
33	Hydro. - Depreciation Exp.	403	0	0	0	0
34	Other Prod. - Depreciation	403	0	0	0	0
35	Trans. - Depreciation Exp.	403	0	0	0	0
36	Distr. - Depreciation Exp.	403	18,274,979	0	0	18,274,979
37	Gen. Plant - Depreciation	403	0	0	0	0
38	Other Depreciation Exp.	404	0	0	0	0
39	Amortization	404	0	0	0	0
40	Other Amort.	Acct. No.	0	0	0	0
41	Other Amort.	Acct. No.	0	0	0	0
42	**Total Depreciation and Amortization**		**18,274,979**	**0**	**0**	**18,274,979**
	Add:					
43	Taxes Other Than Income Taxes		18,778,677	14,910,021	68,897	3,799,759
44	Federal Income Taxes		0	0	0	0
45	State Income Taxes		0	0	0	0
46	**Total Taxes**		**18,778,677**	**14,910,021**	**68,897**	**3,799,759**
	Less:					
47	Sales for Resale		0	0	0	0
48	Other Revenues		9,099,243	0	0	9,099,243
49	Billing Credits		0	0	0	0
50	**Total Operating Expenses**		**$305,824,770**	**$259,274,953**	**$72,604**	**$46,477,212**
51	**Return from Rate Base Schedule 1**		**$20,247,145**	**$4,205,080**	**$1,124,442**	**$14,917,624**
52	**Total Cost**		**$326,071,915**	**$263,480,033**	**$1,197,046**	**$61,394,836**

Clark Public Utilties

Residential Purchase and Sale Agreement
FINAL REPORT
Jurisdiction: Clark Public Utilities

Test Period: October 1, 2005 - September 31, 2006
BPA Docket Number: Run No. 12 10-6-05 Base Case
All Taxes
Dollars in units

Line Number	Account Decription	Total to be Functionalized	Functionalized Amount Production	Transmisison	Distribution
1	Fed Tax-Insurance Contrib.	0	0	0	0
2	Fed Tax-Unemployment	0	0	0	0
3	In-lieu Tax	18,778,677	14,910,021	68,897	3,799,759
4	Other Taxes	0	0	0	0
5	Federal Income Tax	0	0	0	0
6	Total Deferred Taxes	0	0	0	0
7	Miscellaneous Taxes	0	0	0	0
	Washington				
8	State Income Taxes	0	0	0	0
9	State Property Tax	0	0	0	0
10	State Unemp. Tax	0	0	0	0
11	State Reg. Commis. Tax	0	0	0	0
12	State Generating Tax	0	0	0	0
13	State Pollution Control Tax	0	0	0	0
14	State Revenue and Business Tax	0	0	0	0
15	Local Occupation and Franchise Tax	0	0	0	0
16	Misc Taxes	0	0	0	0
17	Other Tax Item	0	0	0	0
18	Other Tax Item	0	0	0	0
	State Two (Put Name Here)				
19	State Income Taxes	0	0	0	0
20	State Property Tax	0	0	0	0
21	State Unemp. Tax	0	0	0	0
22	State Reg. Commis. Tax	0	0	0	0
23	State Generating Tax	0	0	0	0
24	State Pollution Control Tax	0	0	0	0
25	State Rev. & Business Tax	0	0	0	0
26	Local Occupation & Franchise	0	0	0	0
27	Other Tax Item	0	0	0	0
28	Other Tax Item	0	0	0	0
29	Other Tax Item	0	0	0	0
30	**Total Taxes**	$18,778,677	$14,910,021	$68,897	$3,799,759

Clark Public Utilties

Residential Purchase and Sale Agreement
FINAL REPORT
Jurisdiction: Clark Public Utilities

Test Period: October 1, 2005 - September 31, 2006
BPA Docket Number: Run No. 12 10-6-05 Base Case
Other Included Items
Dollars in units

Line Number	Account Decription	Total to be Functionalized	Functionalized Amount Production	Transmisison	Distribution
1	Gain from Disp. of Plant 411.6	0	0	0	0
2	Loss from Disp. of Plant 411.7	0	0	0	0
3	**Total Disp. of Plant**	**0**	**0**	**0**	**0**
	Sale from Resale:				
4	Nonfirm Sales for Resale 447	0	0	0	0
5	Firm Sales For Resale 447	0	0	0	0
6	**Total Sales from Resale**	**0**	**0**	**0**	**0**
	Other Revenues:				
7	Forfeited Discounts 450	0	0	0	0
8	Miscellaneous Service Revenues 451	7,768,165	0	0	7,768,165
9	Sales of water/water power 453	0	0	0	0
10	Rent from property 454	0	0	0	0
11	Interdepartmental Rents 455	0	0	0	0
12	Other electric revenues 456	0	0	0	0
13	Billing Credits	0	0	0	0
14	Other Revenue Acct. No.	776,928	0	0	776,928
15	Other Revenue Acct. No.	554,150	0	0	554,150
16	**Total Other Revenues**	**9,099,243**	**0**	**0**	**9,099,243**
17	**Total Other Included Items**	**$9,099,243**	**$0**	**$0**	**$9,099,243**

Clark Public Utilties

Residential Purchase and Sale Agreement
FINAL REPORT
Jurisdiction: Clark Public Utilities

Test Period: October 1, 2005 - September 31, 2006
BPA Docket Number: Run No. 12 10-6-05 Base Case
Average System Cost
Dollars in units

Line Number	Account Decription	Amount
	Contract System Costs	
1	Production Cost	263,480,033
2	Transmission Cost	1,197,046
3	Less Excluded Costs	0
4	**Total Contract System Costs**	**264,677,079**
	Contract System Load	
6	Total Load (kWh)	4,647,967,387
	Less:	
7	Non-firm Adjustments (kWh)	0
8	Other Adjustments (kWh)	0
9	**Net Load**	**4,647,967,387**
	Plus:	
10	Distribution Losses (kWh)	0
11	**Total Net Load**	**4,647,967,387**
	Less:	
12	Excluded Load (kWh)	0
13	Excl. Load Dist. Losses (kWh)	161,585,926
14	**Total Contract System Load**	**4,486,381,461**
15	**Average System Cost (mills/kWh)**	**59.00**

Clark Public Utilties
Residential Purchase and Sale Agreement
FINAL REPORT
Jurisdiction: Clark Public Utilities

Test Period: October 1, 2005 - September 31, 2006
BPA Docket Number: Run No. 12 10-6-05 Base Case
Dollars in units

Line Number	Account Decription		Total to be Functionalized	Functionalized Amount Production	Transmisison	Distribution
	General Plant: 389-399					
1	Land and Land Rights	389	489,152	0	22,008	467,144
2	Land and Land Rights	389	0	0	0	0
3	Structures and Improvements	390	18,389,177	0	827,374	17,561,803
4	Structures and Improvements	390	0	0	0	0
5	Furniture and Equipment	391	7,387,614	153,368	1,317	7,232,928
6	Furniture and Equipment	391	0	0	0	0
7	Transportation Equipment	392	8,472,587	0	381,202	8,091,385
8	Transportation Equipment	392	0	0	0	0
9	Stores Equipment	393	313,215	0	14,092	299,123
10	Tools and Garage Equipment	394	934,984	0	42,067	892,917
11	Laboratory Equipment	395	344,589	0	15,504	329,085
12	Power Operated Equipment	396	389,289	0	17,515	371,774
13	Communication Equipment	397	1,574,497	0	70,840	1,503,657
14	Miscellaneous Equipment	398	957,429	0	0	957,429
15	Other Tangible Property	399	10,847	0	488	10,359
16	**Total General Plant 389-399**		**39,263,380**	**153,368**	**1,392,409**	**37,717,603**
	Labor Ratio Input:					
17	Production	500-507	390,044	390,044	0	0
18	Transmission	560-573	3,350	0	3,350	0
19	Distribution	580-598	4,346,429	0	0	4,346,429
20	Customer Account	901-905	4,723,188	0	0	4,723,188
21	Customer Service	907-910	51,072	0	0	51,072
22	Sales Expense	911-916	0	0	0	0
23	Admin. & General	920-932	9,273,993	0	0	9,273,993
24	Other Labor	Acct. No.	0	0	0	0
25	Other Labor	Acct. No.	0	0	0	0
26	**Total Labor**		**18,788,076**	**390,044**	**3,350**	**18,394,682**

Clark Public Utilties

Residential Purchase and Sale Agreement
FINAL REPORT
Jurisdiction: Clark Public Utilities

Test Period: October 1, 2005 - September 31, 2006
BPA Docket Number: Run No. 12 10-6-05 Base Case
Cash Working Capital
Dollars in units

Line Number	Account Decription	Total to be Functionalized	Functionalized Amount		
			Production	Transmisison	Distribution
1	Total Production O&M	243,949,602	243,949,602	0	0
2	Total Transmission O&M	0	0	0	0
3	Total Distribution O&M	8,575,874	0	0	8,575,874
4	Customer Accounting Expense	9,060,844	0	0	9,060,844
5	Customer Service Expense	1,221,898	0	0	1,221,898
6	Sales Expense	0	0	0	0
7	Total Administrative and General O&M	15,062,139	415,330	3,708	14,643,102
8	Less Purchased Power and Fuel Costs	(243,949,602)	(243,949,602)	0	0
9	One Eighth O&M Expenses (Less Purch. Power and Fuel Cost	4,240,094	51,916	463	4,187,715
10	Difference from Filing	(4,240,094)	0	0	(4,240,094)
11	Allowable Functionalized Cash Working Capital	**$4,240,094**	**$51,916**	**$51,916**	**$4,187,715**

* Any amount of Purchase Power that is included in the calculation of Cash Working Capital is functionalized to Distribution.

Request Detail

Request ID: BPA-WA-22
Page Number: 40
Line Number: 12-15
Exhibit Filing: WP-07-E-WA-01

Contact Name: Rod Boling
Contact Phone: 503.230.7384
Contact Email: reboling@bpa.gov

Request Text: Please provide all data and analyses relied upon to estimate or determine future natural gas prices for some or all of fiscal years 2002 through 2006 faced by Clark Public Utilities during the Winter/Spring 2001 period.

Response Detail

Date Response Filed: 4/18/2008 12:12:10 PM
Contact Name:
Contact Phone:
Contact Email:
Response Text:
Clark's actual average gas prices were used to estimate the purchased power costs in all years. During the period from 2001-2004, Clark purchased natural gas under a fixed price contract, so the approximate actual cost of gas was known in 2001. Actual prices were also used for the later years. This information is contained in the spreadsheet attached to BPA-WA-21.

Request Detail

Request ID: BPA-WA-36
Page Number: 40
Line Number: 12-15
Exhibit Filing: WP-07-E-WA-5

Contact Name: Rod Boling
Contact Phone: 503.230.7384
Contact Email: reboling@bpa.gov

Request Text: Please provide all data and analyses relied upon by Clark Public Utilities during the Winter/Spring 2001 period to estimate or determine future natural gas prices for some or all of fiscal years 2002 through 2006.

Response Detail

Date Response Filed: 4/18/2008 12:23:50 PM
Contact Name:
Contact Phone:
Contact Email:
Response Text:
During the period from 2001-2004, Clark purchased natural gas under a fixed price contract, so the approximate actual cost of gas was known in 2001. We are not aware of any data or analyses relied upon in 2001 to estimate future gas prices.

Request Detail

Request ID: BPA-WA-23
Page Number: 40
Line Number: 18-22
Exhibit Filing: WP-07-E-WA-01

Contact Name: Rod Boling
Contact Phone: 503.230.7384
Contact Email: reboling@bpa.gov

Request Text: Are you aware of any analyses performed by or for CPU to estimate its ASC any time during the two years prior to Winter/Spring 2001. If so, please provide data and analyses, if available, or describe your understanding of such data and analyses.

Response Detail

Date Response Filed: 4/18/2008 12:12:48 PM
Contact Name:
Contact Phone:
Contact Email:
Response Text:
We are unaware of any such analyses.

Detail

Request ID: BPA-WA-11
Page Number: 37
Line Number: 14-17
Exhibit Filing: WP-07-E-WA-5

Contact Name: Paul McClain
Contact Phone: 503.230.5489
Contact Email: pwtmcclain@bpa.gov

Request Text: Please provide all studies, data, documents, rate orders, FERC Form 1 data, and the ASC Cookbook that you used to develop the ASC for Avista in the above referenced lines. In addition, please identify the year of the ASC and if it was developed to compare with a Backcast ASC.

Response Detail

Date Response Filed: 4/17/2008 1:07:07 PM
Contact Name:
Contact Phone:
Contact Email:
Response Text:

Files Submitted for this Response:
BPA-WA-11.doc
BPA-WA-11_Avista_1983_ASC_FERC_Form_1.xls
BPA-WA-11a.pdf
avista Ferc F1 1983.pdf

DATA REQUEST NUMBER:
BPA-WA-11

DIRECTED TO:
Western Public Agencies Group and Members

REQUESTOR'S NAME:
Rodney Boling - Bonneville Power Administration

EXHIBIT: Direct Testimony of the Western Public Agencies Group WP-07-E-WA-5

PAGE(S): 37
LINE(S): 14-17

DATA REQUEST:
Please provide all studies, data, documents, rate orders, FERC Form 1 data, and the ASC Cookbook that you used to develop the ASC for Avista in the above referenced lines. In addition, please identify the year of the ASC and if it was developed to compare with a Backcast ASC.

DATA RESPONSE:

Attached, please find the FERC Form 1, the Avista ASC filings and the cookbook model used to determine the ASC based on the FERC form 1 data. Please refer to WP-07-E-WA-05-E2

The test year for the ASC is 1/1/1983 – 12/31/1983. The ASC filing was not developed to compare with a Backcast ASC.

Summary of Results

1983 ASC per Filing	$	19.50
ASC using 1983 FERC Form 1		19.81
% Change using FERC Form 1 over Rate Case Filing	1.6%	

Line	Contract System Cost:	Washington	Idaho	Total
1	Production Cost	63,274	38,766	102,040
2	Transmission Cost	14,853	8,856	23,709
3	Less: Excluded Load Cost	0	0	0
4	**Total Contract System Cost**	78,127	47,622	125,749
	Contract System Load:			
5	Total Load (MWH)	3,816,842	2,126,716	5,943,558
	Less:			
6	Nonfirm Adjustment (MWH)	0	0	0
7	Other Adjustments (MWH)	0	0	0
8	Net Load (MWH)	3,816,842	2,126,716	5,943,558
	Plus:			
9	Distribution Losses (MWH)	345,843	159,175	505,018
10	Total Net Load (MWH)	4,162,685	2,285,891	6,448,576
	Less			
11	Excluded Load (MWH)	0	0	0
12	Excluded Load Distribution Losses (MWH)	0	0	0
13	**Total Contract System Load (MWH)**	4,162,685	2,285,891	6,448,576
14	**Average System Cost (mills/kWh) = line 4 / line 13**	**$ 18.77**	**$ 20.83**	**$ 19.50**

Source:

Schedule 4 of Washington Water Power Company filing

Washington Filing Number: 9-A2-8501

Idaho Filing Number: 9-A3-8501

	Washington	Idaho	Total
Rate Base	$442,525	$257,086	$699,611
Rate of Return ($)	$43,500	$25,477	$68,977
Rate of Return (%)	9.830%	9.910%	9.859%

Average System Cost (ASC) COOKBOOK

Utility:	Avista/WWP
FERC FORM 1 Report Date	4/30/1984
End of Year/Period of Report	

BPA DOCKET NO.
LAST APPROVED FILE NUMBER
JURISDICTION:
ANALYST NAME:
REVIEW:
DATE: 31-Mar-08

	(1) Account Description	page number	(2) Account No.(s)	(3) Funct. Method	(4) Total	(5) Production	(6) Transmission	(7) Distribution/ Other	(8) Math Check
Schedule 1: Plant Investment / Rate Base / Rate of Return									
Intangible Plant:									
2	Intangible Plant - Organization	204-207	301	PTD	0	0	0	0	0
3	Intangible Plant - Franchises and Consents	204-207	302	DIR-P	193,079	193,079	0	0	0
4	Intangible Plant - Miscellaneous	204-207	303	PTD	0	0	0	0	0
Total Intangible Plant					193,079	193,079	0	0	0
Production Plant:									
15	Steam Production	204-207	310-316	DIR-P	308,140,863	308,140,863	0	0	0
23	Nuclear Production	204-207	320-325	DIR-P	0	0	0	0	0
32	Hydraulic Production	204-207	330-336	DIR-P	168,176,929	168,176,929	0	0	0
41	Other Production	204-207	340-346	DIR-P	13,123,191	13,123,191	0	0	0
Total Production Plant					489,440,983	489,440,983	0	0	0
Transmission Plant:									
53	Transmission Plant	204-207	350-359	DIR-T	111,456,312	0	111,456,312	0	0
Total Transmission Plant					111,456,312	0	111,456,312	0	0
Distribution Plant:									
69	Distribution Plant	204-207	360-373	DIR-D	258,910,751	0	0	258,910,751	0
Total Distribution Plant					258,910,751	0	0	258,910,751	0

General Plant:			389-399						
71	Land and Land Rights	204-207	389	PTD	1,251,948	712,664	162,289	376,994	0
72	Structures and Improvements	204-207	390	PTD	21,448,452	12,209,413	2,780,348	6,458,691	0
73	Furniture and Equipment	204-207	391	PTD	9,416,982	5,360,565	1,220,717	2,835,700	0
74	Transportation Equipment	204-207	392	TD	6,657,210	0	2,003,386	4,653,824	0
75	Stores Equipment	204-207	393	PTD	243,166	138,421	31,521	73,224	0
76	Tools and Garage Equipment	204-207	394	PTD	1,214,786	691,510	157,472	365,804	0
77	Laboratory Equipment	204-207	395	PTD	542,841	309,009	70,368	163,464	0
78	Power Operated Equipment	204-207	396	TD	4,639,995	0	1,396,336	3,243,659	0
79	Communication Equipment	204-207	397	PTD	4,064,070	2,313,449	526,823	1,223,798	0
80	Miscellaneous Equipment	204-207	398	DIR-D	138,815	0	0	138,815	0
Total General Plant					49,618,265	21,735,032	8,349,259	19,533,974	0
Total Electric Plant In-Service					909,619,390	511,369,094	119,805,571	278,444,725	0
(Total Intangible + Total Production + Total Transmission + Total Distribution + Total General)									
LESS:									
Depreciation Reserve									
18	Steam (Production) Plant	219	108	DIR-P	14,758,596	14,758,596	0	0	0
19	Nuclear (Production) Plant	219	108	DIR-P	0	0	0	0	0
20	Hydraulic (Production) Plant - Conventional	219	0	DIR-P	21,829,684	21,829,684	0	0	0
21	Hydraulic (Production) Plant - Pumped Storage	219	108	DIR-P	0	0	0	0	0
22	Other (Production) Plant	219	108	DIR-P	2,984,614	2,984,614	0	0	0
23	Transmission Plant	219	108	DIR-T	25,452,430	0	25,452,430	0	0
24	Distribution Plant	219	108	DIR-D	64,123,130	0	0	64,123,130	0
25	General Plant	219	108	GP	12,679,862	5,554,350	2,133,639	4,991,873	0
0	Accumulated Provision for Depreciation, Amortization, & Depletion (In-Ser	200-201	108	GP	0	0	0	0	0
0	Accumulated Provision for Depreciation, Amortization, & Depletion (Amorti	200-201	108	GP	104,935	45,966	17,657	41,311	0
0	Amortization of Plant Acquisition Adjustments (Electric)	200-201	108	DIR-P	0	0	0	0	0
Amortization Reserve									
Total Depreciation and Amortization					141,933,251	45,173,210	27,603,726	69,156,315	0
Total Net Plant					767,686,139	466,195,884	92,201,845	209,288,410	0
(Total Electric Plant In-Service) - (Total Depreciation & Amortization)									
Assets and Other Debits (Comparative Balance Sheet)									
0	Cash Working Capital			Formula					0

	UTILITY PLANT								
10	(Utility Plant) Held For Future Use	200-201	105	PTDG	0	0	0	0	0
6	(Utility Plant) Completed Construction - Not Classified	200-201	106	PTD	0	0	0	0	0
3	(Utility Plant) In Service (Classified) COMMON	200-201		PTD	0	0	0	0	0
0	Nuclear Fuel	0	20.2-120.4 less120	DIR-P					
11	Construction Work in Progress (CWIP) - ELECTRIC	200-201	107-120.1	DIR-D	219,969,360	0	0	219,969,360	0
0	Acquisition Adjustments (Electric)	200-201	0	LABOR	0	0	0	0	0
	Total				219,969,360	0	0	219,969,360	0
	OTHER PROPERTY AND INVESTMENTS								
20	Other Investment	110-111	124	DIR-D	16,725,531	0	0	16,725,531	0
0	Long-Term Portion of Derivative Assets (175)	110-111	175	DIR-P	0	0	0	0	0
0	Long-Term Portion of Derivative Assets – Hedges (176)	110-111	176	DIR-P	0	0	0	0	0
	Total				16,725,531	0	0	16,725,531	0
	CURRENT AND ACCRUED ASSETS								
34	Fuel Stock	110-111	151	DIR-P	7,410,744	7,410,744	0	0	0
35	Fuel Stock Expenses Undistributed (152)	110-111	152	DIR-P	0	0	0	0	0
37	Plant Materials and Operating Supplies	110-111	154	TDG	6,635,014	0	1,996,010	4,639,004	0
39	Other Materials and Supplies	110-111	156	TDG	0	0	0	0	0
43	Stores Expense Undistributed	110-111	163	TDG	(9,447)	0	(2,842)	(6,605)	0
46	Prepayments (165)	110-111	165	PTD	363,915	207,157	47,174	109,584	0
52	Derivative Instrument Assets (175)	110-111	175	DIR-P	0	0	0	0	0
0	(Less) Long-Term Portion of Derivative Instrument Assets (175)	110-111	175	DIR-P		0	0	0	0
53	Derivative Instrument Assets - Hedges (176)	110-111	176	DIR-P	0	0	0	0	0
0	(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176	110-111	176	DIR-P		0	0	0	0
	Total				14,400,226	7,617,901	2,040,342	4,741,983	0
	DEFERRED DEBITS								
56	Unamortized Debt Expenses (181)	110-111	181	PTDG	371,461	208,828	48,925	113,708	0
57	Extraordinary Property Losses (182.1)	110-111	182.1	DIR-D	0	0	0	0	0
58	Unrecovered Plant and Regulatory Study Costs (182.2)	110-111	182.2	DIR-P	0	0	0	0	0
0	Other Regulatory Assets (182.3)	232	See Tab	DIRECT	0	0	0	0	0
60	Prelim. Survey and Investigation Charges (Electric) (183)	110-111	183	DIR-D	10,496,180	0	0	10,496,180	0
61	Preliminary Natural Gas Survey and Investigation Charges 183.1)	110-111	183.1	DIR-D	0	0	0	0	0
0	Other Preliminary Survey and Investigation Charges (183.2)	110-111	183.2	DIR-D					
62	Clearing Accounts (184)	110-111	184	LABOR	217,800	68,467	17,871	131,462	0
63	Temporary Facilities (185)	110-111	185	PTDG	0	0	0	0	0
0	Miscellaneous Deferred Debits (186)	233-234	See Tab	DIRECT	53,544,532	53,539,322	122,039	(116,830)	0
65	Deferred Losses from Disposition of Utility Plant. (187)	110-111	187	PTD	0	0	0	0	0
66	Research, Development, and Demonstration Expenditures (188)	110-111	188	DIR-D	0	0	0	0	0
67	Unamortized Loss on Reacquired Debt (189)	110-111	189	PTDG	75,844	42,638	9,989	23,217	0
68	Accumulated Deferred Income Taxes (190)	110-111	190	DIR-D	0	0	0	0	0
69	Unrecovered Purchased Gas Costs (191)	110-111	191	DIR-P	0	0	0	0	0
	Total				64,705,817	53,859,255	198,825	10,647,738	

	Total Assets and Other Debits				315,800,934	61,477,155	2,239,167	252,084,612	0
	LESS:								
	Liabilities and Other Credits (Comparative Balance Sheet)								
	OTHER NONCURRENT LIABILITIES								
0	Long-Term Portion of Derivative Instrument Liabilities	112-113	0	DIR-P		0	0	0	0
0	Long-Term Portion of Derivative Instrument Liabilities - Hedges	112-113	0	DIR-P		0	0	0	0
	Total				0	0	0	0	0
	CURRENT AND ACCRUED LIABILITIES								
46	Derivative Instrument Liabilities (244)	112-113	244	DIR-P	0	0	0	0	0
0	(Less) Long-Term Portion of Derivative Instrument Liabilities	112-113	0	DIR-P	0	0	0	0	0
47	Derivative Instrument Liabilities - Hedges (245)	112-113	244	DIR-P	0	0	0	0	0
0	(Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges	112-113	0	DIR-P	0	0	0	0	0
	Total				0	0	0	0	0
	DEFERRED CREDITS								
50	Customer Advances for Construction (252)	112-113	252	DIR-D	485,386	0	0	485,386	0
51	Accumulated Deferred Investment Tax Credits (255)	112-114	255	DIR-D	39,317,877	0	0	39,317,877	0
52	Deferred Gains from Disposition of Utility Plant (256)	112-115	256	PTDG	0	0	0	0	0
0	Other Deferred Credits (253)	269	See Tab	DIRECT	2,715,928	2,398,245	0	317,683	0
0	Other Regulatory Liabilities (254)	278	See Tab	DIRECT	0	0	0	0	0
55	Unamortized Gain on Reacquired Debt (257)	112-118	257	PTDG	0	0	0	0	0
56	Accumulated. Deferred Income Taxes-Accelerated. Amort.(281)	112-119	281	DIR-D	19,581,445	0	0	19,581,445	0
56	Accumulated. Deferred Income Taxes-Property (282)	112-120	282	DIR-D		0	0	0	0
56	Accumulated. Deferred Income Taxes-Other (283)	112-121	283	DIR-D	0	0	0	0	0
	Total				62,100,636	2,398,245	0	59,702,391	0
	Total Liabilities and Other Credits				62,100,636	2,398,245	0	59,702,391	0
	Total Rate Base				1,021,386,437	525,274,794	94,441,012	401,670,632	0
	(Total Net Plant + Debits - Credits)								

Schedule 2: Long Term Debt

Long Term Debt	257		
Preferred Stock			
Common Stock			
Interest for Year	257		
Interest Rate			
Authorized Return Preferred			
Authorized Return Common			
Weighted Cost of Capital			
Rate of Return			9.859%

(Interest for Year / Long Term Debt)

Schedule 3: Expenses

Power Production Expenses:

	Steam Power Generation								
5	Steam - Fuel	320-323	501	DIR-P	16,201,634	16,201,634	0	0	0
13	Steam - Operation (less fuel)	320-323	500-509	DIR-P	1,250,399	1,250,399	0	0	0
20	Steam - Maintenance	320-323	510-514	DIR-P	2,350,932	2,350,932	0	0	0
	Nuclear Power Generation								
25	Nuclear - Fuel	320-323	518	DIR-P	0	0	0	0	0
33	Nuclear - Operation (less fuel)	320-323	517-525	DIR-P	0	0	0	0	0
40	Nuclear - Maintenance	320-323	528-532	DIR-P	0	0	0	0	0
	Hydraulic Power Generation								
50	Hydraulic - Operation	320-323	535-540	DIR-P	2,757,912	2,757,912	0	0	0
58	Hydraulic - Maintenance	320-323	541-545	DIR-P	1,114,843	1,114,843	0	0	0
	Other Power Generation								
63	Other Power - Fuel	320-323	547	DIR-P	239,407	239,407	0	0	0
67	Other Power - Operations (less fuel)	320-323	546-550	DIR-P	38,346	38,346	0	0	0
73	Other Power - Maintenance	320-323	551-554	DIR-P	21,833	21,833	0	0	0
	Other Power Supply Expenses								
76	Purchased Power	320-323	555	DIR-P	51,871,714	51,871,714	0	0	0
77	System Control and Load Dispatching	320-323	556	DIR-P	489,506	489,506	0	0	0
78	Other Expenses	320-323	557	DIR-P	41,564	41,564	0	0	0
0	BPA REP Reversal	0	0	DIR-P		0	0	0	0
0	Oregon Public Purpose Charge	0	0	DIR-C		0	0	0	0
Total Production Expense					76,378,090	76,378,090	0	0	0

Transmission Expenses:

88	Transmission of Electricity to Others (Wheeling)	320-323	565	DIR-T	4,401,232	0	4,401,232	0	0
91	Total Operations less Wheeling	320-323	560-567	DIR-T	849,729	0	849,729	0	0
99	Total Maintenance	320-323	568-573	DIR-T	761,531	0	761,531	0	0
Total Transmission Expense					6,012,492	0	6,012,492	0	0

Distribution Expense:

114	Total Operations	320-323	580-589	DIR-D	2,893,414	0	0	2,893,414	0
125	Total Maintenance	320-323	590-598	DIR-D	3,616,354	0	0	3,616,354	0
Total Distribution Expense					6,509,768	0	0	6,509,768	0

Customer and Sales Expenses:

134	Total Customer Accounts	320-323	901-905	DIR-D	6,508,514	0	0	6,508,514	0
141	Total Customer Service and Information	320-323	907-910	DIR-D	2,941,828	0	0	2,941,828	0
148	Total Sales	320-323	911-916	DIR-D	135,002	0	0	135,002	0
Total Customer and Sales Expenses					9,585,344	0	0	9,585,344	0

Administration and General Expense:

	Operation								
151	Administration and General Salaries	320-323	920	LABOR	3,597,282	1,130,826	295,164	2,171,292	0
152	Office Supplies & Expenses	320-323	921	LABOR	1,121,720	352,619	92,039	677,062	0
153	(Less) Administration Expenses Transferred - Credit	320-323	922	LABOR	(327,776)	(103,038)	(26,895)	(197,843)	0
155	Outside Services Employed	320-323	923	LABOR	826,421	259,790	67,809	498,821	0
156	Property Insurance	320-323	924	PTDG	172,418	96,930	22,709	52,779	0
157	Injuries and Damages	320-323	925	LABOR	926,748	291,328	76,041	559,378	0
158	Employee Pensions & Benefits	320-323	926	LABOR	4,719,169	1,483,497	387,217	2,848,455	0
159	Franchise Requirements	320-323	927	DIR-D	711,121	0	0	711,121	0
160	Regulatory Commission Expenses	320-323	928	DIR-D	1,582,177	0	0	1,582,177	0
161	(Less) Duplicate Charges - Credit	320-323	929	PTDG	0	0	0	0	0
162	General Advertising Expenses	320-323	930.1	DIR-D	49,516	0	0	49,516	0
163	Miscellaneous General Expenses	320-323	930.2	PTD	2,247,716	1,279,500	291,370	676,846	0
164	Rents	320-323	931	PTD	587,813	334,609	76,198	177,006	0
	Maintenance								
167	Maintenance of General Plant	320-323	935	GPM	871,318	494,030	112,501	264,787	0
Total Administration and General Expenses					17,085,643	5,620,092	1,394,154	10,071,398	0

Total Operations and Maintenance	115,571,337	81,998,182	7,406,646	26,166,510	0

(Total Expenses: Production + Transmission + Distribution + Customer and Sales +Total Administration and General Expenses)

Depreciation and Amortization:

1	Intangible Plant	336	403	PTD	0	0	0	0	0
2	Steam Production Plant	336	403	DIR-P	5,676,897	5,676,897	0	0	0
3	Nuclear Production Plant	336	403	DIR-P	0	0	0	0	0
4	Hydraulic Production Plant - Conventional	336	403	DIR-P	1,234,485	1,234,485	0	0	0
5	Hydraulic Production Plant - Pumped Storage	336	403	DIR-P	0	0	0	0	0
6	Other Production Plant	336	403	DIR-P	522,782	522,782	0	0	0
7	Transmission Plant	336	403	DIR-T	2,234,374	0	2,234,374	0	0
8	Distribution Plant	336	403	DIR-D	6,789,895	0	0	6,789,895	0
9	General Plant	336	403	GP	1,302,043	570,353	219,095	512,595	0
10	Common Plant - Electric	336	404	PTD	0	0	0	0	0
Total Depreciation and Amortization					17,760,476	8,004,517	2,453,469	7,302,490	0

Schedule 3A Items: Taxes

Taxes Accrued, Prepaid, and Charged During Year

FEDERAL								
Total Federal	262	See Tab	DIRECT	2,463,276	783,448	204,493	1,475,336	0
STATE								
Montana	262	-		4,318,815	2,002,464	478,433	1,837,917	0
Washington	262	-		13,352,801	1,936,386	457,001	10,959,414	0
Idaho	262	-		1,736,799	627,829	147,090	961,880	0
Canada	262	-		2,659	0	0	2,659	0
Total State	262	See Tab	DIRECT	19,411,074	4,566,679	1,082,525	13,761,870	
County & Municipal								
Total County and Municipal	262	See Tab	DIRECT	6,106,692	19,480	4,564	6,082,649	0
Total Taxes				27,981,042	5,369,607	1,291,581	21,319,854	0

(Total Federal, State and County/Municipal Taxes)

Schedule 3B Items: Other Included Items

Other Included Items:

19	(Less) Gain from Disposition. of Plant	114	411.6	PTDG	0	0	0	0	0
20	Loss from Disposition of Plant	114	411.7	PTDG	0	0	0	0	0
Total Disposition of Plant					0	0	0	0	

Sale for Resale:

0	Sales for Resale	300	447	DIR-P	40,873,753	40,873,753	0	0	0
Total Sales for Resale					40,873,753	40,873,753	0	0	

Other Revenues:

16	Forfeited Discounts	300	450	DIR-P	0	0	0	0	0
17	Miscellaneous Service Revenues	300	451	DIR-P	83,682	83,682	0	0	0
18	Sales of Water and Water Power	300	453	DIR-P	390,654	390,654	0	0	0
19	Rent from Electric Property	300	454	DIR-P	705,060	705,060	0	0	0
20	Interdepartmental Rents	300	455	DIR-P	0	0	0	0	0
21	Other Electric Revenues (less Revenues from Trans of Electricity to Others	300	456	DIR-P	(2,672,843)	(2,672,843)	0	0	0
22	Revenues from Transmission of Electricity of Others	300 (330)	456.1	DIR-T	4,064,169	0	4,064,169	0	0
23	Regional Control Service Revenues	300	457.1	DIR-T	0	0	0	0	0
24	Miscellaneous Revenues	300	457.2	DIR-T	0	0	0	0	0
Total Other Revenues					2,570,722	(1,493,447)	4,064,169	0	

Total Other Included Items *(Total Disposition of Plant + Total Sales from Resale + Total Other Revenue)*	43,444,475	39,380,306	4,064,169	0	0
Total Operating Expenses *(Total O&M + Total Depreciation & Amortization + Total Taxes - Total Other Included Items)*	117,868,380	55,992,000	7,087,526	54,788,854	0
Return from Rate Base *(Total Rate Base * Rate of Return)*	100,701,922	51,788,607	9,311,257	39,602,058	0
Total Cost *(Total Operating Expenses + Return from Rate Base)*	218,570,302	107,780,607	16,398,783	94,390,912	0

Schedule 4: Average System Cost

Energy Measure (MWh)			(MWh)		
Total Load			5,970,446	pg 301	
Non-firm Adjustments			0		
Other Adjustments			0		
Distribution Losses			298,522	5% of Total Load	6,268,968
Excluded Load			0		
Excl. Load Dist. Losses			0		
Excluded Load Costs			0		**% Change**
Revenue Requirement			0		**due to**
ASC Multiplier			1	**Original ASC**	**FERC Form 1**
Schedule 4 ASC	$/MWh	$/MWh	**19.81**	**19.50**	**1.6%**

Schedule 3A Items: Taxes (Including Income Taxes)

Taxes Accrued, Prepaid, and Charged During Year

FEDERAL								
FERC Resale/Coord Charges	262	-	DIR-D	0	0	0	0	0
Income Tax	262	-	DIR-D	(43,334)	0	0	(43,334)	0
FICA (Employer share)	262	-	LABOR	0	0	0	0	0
Unemployment Compensation	262	-	LABOR	78,339	24,626	6,428	47,285	0
Ins. Contr. Act	262	-	LABOR	2,413,895	758,822	198,065	1,457,009	0
Use Tax - Mtr. Vehicle	262	-	DIR-D	14,376	0	0	14,376	0
Subtotal Federal	262	-		2,463,276	783,448	204,493	1,475,336	0
State of Montana:	262	-		0	0	0	0	0
Income Tax	262	-	DIR-D	185,621	0	0	185,621	0
Elec. Energy Producers Tax	262	-	DIR-D	83,352	0	0	83,352	0
Unemployment Insurance	263	-	LABOR	1,105,283	347,452	90,691	667,140	0
Motor Vehicle	264	-	DIR-D	636	0	0	636	0
Property Taxes	262	-	PTDG	2,943,923	1,655,012	387,743	901,168	0
Subtotal Montana	262	-		4,318,815	2,002,464	478,433	1,837,917	0
State of Washington:	262	-		0	0	0	0	0
Property Taxes	262	-	PTDG	3,222,396	1,811,564	424,420	986,412	0
Excise Tax	263	-	DIR-D	9,612,545	0	0	9,612,545	0
Unemploy. Ins.	264	-	LABOR	397,074	124,822	32,581	239,671	0
Motor Vehicle	262	-	Dir-D	120,786	0	0	120,786	
Subtotal Washington	262	-		13,352,801	1,936,386	457,001	10,959,414	0
Idaho	262	-		0	0	0	0	0
Income Taxes	262	-	DIR-D	620,022	0	0	620,022	0
Property Taxes	262	-	PTDG	1,116,777	627,829	147,090	341,858	0
kWh tax	263	-	DIR-D	366,090	0	0	366,090	0
Unemploy. Tax	264	-	LABOR	46,858	14,730	3,845	28,283	0
Excise Tax	265	-	DIR-D	13,836	0	0	13,836	0
Motor Vehicle	266	-	DIR-D	9,948	0	0	9,948	0
Mileage Use	267	-	DIR-D	1,863	0	0	1,863	0
Subtotal Idaho	262	-		1,736,799	627,829	147,090	961,880	0
County & Municipal	262	-		0	0	0	0	0
Occupation	262	-	DIR-D	6,032,319	0	0	6,032,319	0
Real Estate	263	-	PTDG	34,650	19,480	4,564	10,607	0
Use of Streets	264	-	DIR-D	25,225	0	0	25,225	0
Paving Assessment	265	-	DIR-D	3,868	0	0	3,868	0
Spokane Bus. Lic.	263	-	Dir-D	10,630	0	0	10,630	0
Subtotal County & Muni	262	-		6,106,692	19,480	4,564	6,082,649	0
Canada Income Tax	262	-	DIR-D	2,659	0	0	2,659	0
Subtotal Canada	262	-		2,659	0	0	2,659	0

				(2)	(3)	(4)	(5)	(6)	(7)	
72	**Other Regulatory Assets (182.3)**		Page No	Account No	Funct Method	Total	Production	Transmission	Distribution	
1		0	232			-	-	-	-	-
2		0	232			-	-	-	-	-
3		0	232			-	-	-	-	-
4		0	232			-	-	-	-	-
5		0	232			-	-	-	-	-
6		0	232			-	-	-	-	-
7		0	232			-	-	-	-	-
8		0	232			-	-	-	-	-
9		0	232			-	-	-	-	-
10		0	232			-	-	-	-	-
11		0	232			-	-	-	-	-
12		0	232			-	-	-	-	-
13		0	232			-	-	-	-	-
14		0	232			-	-	-	-	-
15		0	232			-	-	-	-	-
16		0	232			-	-	-	-	-
17		0	232			-	-	-	-	-
18		0	232			-	-	-	-	-
19		0	232			-	-	-	-	-
20			232			-	-	-	-	-
21		0	232			-	-	-	-	-
22		0	232			-	-	-	-	-
23		0	232			-	-	-	-	-
24		0	232			-	-	-	-	-
25		0	232			-	-	-	-	-
26		0	232			-	-	-	-	-
27		0	232			-	-	-	-	-
28		0	232			-	-	-	-	-
29		0	232			-	-	-	-	-
30		0	232			-	-	-	-	-
31		0	232			-	-	-	-	-
32		0	232			-	-	-	-	-
33		0	232			-	-	-	-	-
34		0	232			-	-	-	-	-
35		0	232			-	-	-	-	-
36		0	232			-	-	-	-	-
37		0	232			-	-	-	-	-
38		0	232			-	-	-	-	-
39		0	232			-	-	-	-	-
40		0	232			-	-	-	-	-
41		0	232			-	-	-	-	-
42		0	232			-	-	-	-	-
43		0	232			-	-	-	-	-
44		0	232			-	-	-	-	-
45		0	232			-	-	-	-	-
46		0	232			-	-	-	-	-
47		0	232			-	-	-	-	-
48		0	232			-	-	-	-	-
49		0	232			-	-	-	-	-
50		0	232			-	-	-	-	-
51		0	232			-	-	-	-	-
52		0	232			-	-	-	-	-
53		0	232			-	-	-	-	-
	Total					-	-	-	-	-

72	**Miscellaneous Deferred Debit Details**		Page No	Account No	Funct Method	Total	Production	Transmission	Distribution	
2	Misc. undistributed charges		233			-	-	-	-	-
2	(9 items)		233		PTD	144,462	82,234	18,727	43,501	-
3			233	182.3		-	-	-	-	-
4	Water Heater Insulation		233			-	-	-	-	-
5	Blankets - WA (3 years)		233			-	-	-	-	-
6		0	233	182.31&182.32		-	-	-	-	-
7	Water Heater Insulation		233	182.35		-	-	-	-	-
8	Blankets - ID (3 years)		233	182.36		-	-	-	-	-
9		0	233			-	-	-	-	-
10	Company Home Sale Plan for		233	182.39		-	-	-	-	-
11	Managers' Relocation (13 items)		233	182.39	LABOR	276,525	86,927	22,689	166,908	-
12		0	233	182.45		-	-	-	-	-
13	Residential Purchase and Sale		233	182.45		-	-	-	-	-
14	Agreement - BPA		233	182.46	Dir-P	50,644	50,644	-	-	-
15		0	233	182.46		-	-	-	-	-
16	Southern CA Edison Co.		233	182.76	Dir-P	1,081,568	1,081,568	-	-	-
17		0	233	182.8		-	-	-	-	-
18	Weatherization Grants (6-9 years)		233	182.83	DIR-P	11,497,471	11,497,471	-	-	-
19		0	233			-	-	-	-	-
20	Undelivered Coal-WIDCo		233		Dir-P	928,446	928,446	-	-	-
21		0	233			-	-	-	-	-
22	Street Light Change		233			-	-	-	-	-
23	Washington		233		Dir-D	(395,993)	-	-	(395,993)	-
24		0	233			-	-	-	-	-
25	Street Light Change		233			-	-	-	-	-
26	Idaho		233		Dir-D	(118,533)	-	-	(118,533)	-
27		0	233			-	-	-	-	-
28	Return of Ratepayer Contributions		233			-	-	-	-	-
29	in Excess of Refund - Gas		233			-	-	-	-	-
30	Exploration Advance		233		Dir-P	118,124	118,124	-	-	-
31			233			-	-	-	-	-
32	Investment in Terminated Nuclear		233			-	-	-	-	-
33	Project (Skagit)		233		Dir-P	39,339,840	39,339,840	-	-	-
34			233			-	-	-	-	-
35			233			-	-	-	-	-
36			233			-	-	-	-	-
37			233			-	-	-	-	-
38			233			-	-	-	-	-
39			233			-	-	-	-	-
40			233			-	-	-	-	-
41			233			-	-	-	-	-
42			233			-	-	-	-	-
43			233			-	-	-	-	-
44			233			-	-	-	-	-
45			233			-	-	-	-	-
46			233			-	-	-	-	-
47	Misc work in progress (hard copy - not electronic download)		233			-	-	-	-	-
48	Misc Work in Progress		233		PTD	621,954	354,044	80,623	187,287	-
49	Deferred Regulatory Commission Expenses		233		DIR-P	24	24	-	-	-
50		0	233			-	-	-	-	-
51		0	233			-	-	-	-	-
52		0	233			-	-	-	-	-
53		0	233			-	-	-	-	-
54		0	233			-	-	-	-	-
	TOTAL					53,544,532	53,539,322	122,039	(116,830)	0

				(2)	(3)	(4)	(5)	(6)	(7)	
72	**Other Deferred Credits**		Page No	Account No	Funct Methof	Total	Production	Transmission	Distribution	
1	Unearned interest -		269			-	-	-	-	-
2	Customer wiring and installation contracts		269		DIR-D	94,609	-	-	94,609	-
3		0	269			-	-	-	-	-
4	Water amortization -		269			-	-	-	-	-
5	Plant in Service		269			-	-	-	-	-
6		0	269			-	-	-	-	-
7	Gas Exploration Advance -		269			-	-	-	-	-
8	Develop Assoc Inc.		269			-	-	-	-	-
9		0	269			-	-	-	-	-
10	Gas Refund - WA		269		DIR-P	1,325,919	1,325,919	-	-	-
11		0	269			-	-	-	-	-
12	Gas Refund - ID		269		DIR-P	282,041	282,041	-	-	-
13		0	269			-	-	-	-	-
14	Accum. Credits Allowed under		269			-	-	-	-	-
15	BPA Res Exchange		269			-	-	-	-	-
16	Agreement WA		269		Dir-D	(147,087)	-	-	(147,087)	-
17			269			-	-	-	-	-
18	BPA Conservation Program		269			-	-	-	-	-
19	Excess Reimbursement		269		Dir-C	1,128,979	790,285	-	338,694	-
20		0	269			-	-	-	-	-
21	Deferred Compensation		269		DIR-D	31,467	-	-	31,467	-
22			269			-	-	-	-	-
23			269			-	-	-	-	-
24			269			-	-	-	-	-
25			269			-	-	-	-	-
26			269			-	-	-	-	-
27			269			-	-	-	-	-
28			269			-	-	-	-	-
29			269			-	-	-	-	-
30			269			-	-	-	-	-
31			269			-	-	-	-	-
32			269			-	-	-	-	-
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	Total					2,715,928	2,398,245	-	317,683	-
72	**Other Regulatory Liabilities**		Page No	Account No	Funct Methof	Total	Production	Transmission	Distribution	
2		0	278			-	-	-	-	-
2		0	278			-	-	-	-	-
2		0	278			-	-	-	-	-
2		0	278			-	-	-	-	-
2		0	278			-	-	-	-	-
2		0	278			-	-	-	-	-
2		0	278			-	-	-	-	-
2		0	278			-	-	-	-	-
2		0	278			-	-	-	-	-
2		0	278			-	-	-	-	-
2			278			-	-	-	-	-
2			278			-	-	-	-	-
2			278			-	-	-	-	-
2			278			-	-	-	-	-
2			278			-	-	-	-	-
2			278			-	-	-	-	-
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2			278			-	-	-	-	-
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2		0	278			-	-	-	-	-
2		0	278			-	-	-	-	-
2		0	278			-	-	-	-	-
2		0	278			-	-	-	-	-
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2		0	278			-	-	-	-	-
2		0	278			-	-	-	-	-
2		0	278			-	-	-	-	-
2		0	278			-	-	-	-	-
2		0	278			-	-	-	-	-
	Total					-	-	-	-	-

row_number	row_lit	end_bal
1	UTILITY PLANT	0
2	Utility Plant (101-106, 114)	820948975
3	Construction Work in Progress (107)	392954161
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)	1213903136
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 111, 115)	167239642
6	Net Utility Plant (Enter Total of line 4 less 5)	1046663494
7	Nuclear Fuel (120.1-120.4, 120.6)	2941784
8	(Less) Accum. Prov. for Amort. of Nucl. Fuel Assemblies (120.5)	0
9	Net Nuclear Fuel (Enter Total of line 7 less 8)	2941784
10	Net Utility Plant (Enter Total of lines 6 and 9)	1049605278
11	Utility Plant Adjustments (116)	0
12	Gas Stored Underground - Noncurrent (117)	0
13	OTHER PROPERTY AND INVESTMENTS	0
14	Nonutility Property (121)	1383627
15	(Less) Accum. Prov. for Depr. and Amort. (122)	36364
16	Investments in Associated Companies (123)	0
17	Investment in Subsidiary Companies (123.1)	35826213
18	(For Cost of Account 123.1, See Footnote Page 224, line 42)	0
19	Noncurrent Portion of Allowances	0
20	Other Investments (124)	16725531
21	Special Funds (125-128)	0
22	TOTAL Other Property and Investments (Total of lines 14-17,19-21)	5389907
23	CURRENT AND ACCRUED ASSETS	0
24	Cash (131)	186080
25	Special Deposits (132-134)	
26	Working Fund (135)	254791
27	Temporary Cash Investments (136)	0
28	Notes Receivable (141)	62054
29	Customer Accounts Receivable (142)	27870036
30	Other Accounts Receivable (143)	9153085
31	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)	1567970
32	Notes Receivable from Associated Companies (145)	0
33	Accounts Receivable from Assoc. Companies (146)	32272
34	Fuel Stock (151)	7410744
35	Fuel Stock Expenses Undistributed (152)	0
36	Residuals (Elec) and Extracted Products (153)	0
37	Plant Materials and Operating Supplies (154)	6635014
38	Merchandise (155)	0
39	Other Materials and Supplies (156)	0
40	Nuclear Materials Held for Sale (157)	0
41	Allowances (158.1 and 158.2)	0

42	(Less) Noncurrent Portion of Allowances	0
43	Stores Expense Undistributed (163)	-9447
44	Gas Stored Underground - Current (164.1)	4953162
45	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)	189479
46	Prepayments (165)	363915
47	Advances for Gas (166-167)	0
48	Interest and Dividends Receivable (171)	12782
49	Rents Receivable (172)	101152
50	Accrued Utility Revenues (173)	0
51	Miscellaneous Current and Accrued Assets (174)	112148
52	Derivative Instrument Assets (175)	0
53	Derivative Instrument Assets - Hedges (176)	0
54	TOTAL Current and Accrued Assets (Enter Total of lines 24 thru 53)	55759297
55	DEFERRED DEBITS	0
56	Unamortized Debt Expenses (181)	371461
57	Extraordinary Property Losses (182.1)	0
58	Unrecovered Plant and Regulatory Study Costs (182.2)	0
59	Other Regulatory Assets (182.3)	0
60	Prelim. Survey and Investigation Charges (Electric) (183)	10496180
61	Prelim. Sur. and Invest. Charges (Gas) (183.1, 183.2)	0
62	Clearing Accounts (184)	217800
63	Temporary Facilities (185)	0
64	Miscellaneous Deferred Debits (186)	53544532
65	Def. Losses from Disposition of Utility Plt. (187)	0
66	Research, Devel. and Demonstration Expend. (188)	0
67	Unamortized Loss on Reaquired Debt (189)	75844
68	Accumulated Deferred Income Taxes (190)	0
69	Unrecovered Purchased Gas Costs (191)	0
70	TOTAL Deferred Debits (Enter Total of lines 56 thru 69)	68048957
71	TOTAL Assets and Other Debits (Enter Total of lines 10,11,12,22,54,70	1227312539

row_number	row_lit	end_bal
1	PROPRIETARY CAPITAL	0
2	Common Stock Issued (201)	362031658
3	Preferred Stock Issued (204)	95000000
4	Capital Stock Subscribed (202, 205)	0
5	Stock Liability for Conversion (203, 206)	0
6	Premium on Capital Stock (207)	0
7	Other Paid-In Capital (208-211)	0
8	Installments Received on Capital Stock (212)	49805
9	(Less) Discount on Capital Stock (213)	0
10	(Less) Capital Stock Expense (214)	2016200
11	Retained Earnings (215, 215.1, 216)	77774374
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	17441219
13	(Less) Reaquired Capital Stock (217)	0
14	Accumulated Other Comprehensive Income (219)	0
15	TOTAL Proprietary Capital (Enter Total of lines 2 thru 13)	550280856
16	LONG-TERM DEBT	0
17	Bonds (221)	410135000
18	(Less) Reaquired Bonds (222)	0
19	Advances from Associated Companies (223)	0
20	Other Long-Term Debt (224)	157461121
21	Unamortized Premium on Long-Term Debt (225)	575456
22	(Less) Unamortized Discount on Long-Term Debt-Debit (226)	428387
23	TOTAL Long-Term Debt (Enter Total of lines 16 thru 21)	567743190
24	OTHER NONCURRENT LIABILITIES	0
25	Obligations Under Capital Leases - Noncurrent (227)	0
26	Accumulated Provision for Property Insurance (228.1)	0
27	Accumulated Provision for Injuries and Damages (228.2)	0
28	Accumulated Provision for Pensions and Benefits (228.3)	0
29	Accumulated Miscellaneous Operating Provisions (228.4)	0
30	Accumulated Provision for Rate Refunds (229)	0
31	TOTAL OTHER Noncurrent Liabilities (Enter Total of lines 24 thru 29)	0
32	CURRENT AND ACCRUED LIABILITIES	0
33	Notes Payable (231)	0
34	Accounts Payable (232)	17849112
35	Notes Payable to Associated Companies (233)	2147000
36	Accounts Payable to Associated Companies (234)	56300
37	Customer Deposits (235)	303306
38	Taxes Accrued (236)	6617124
39	Interest Accrued (237)	15945628
40	Dividends Declared (238)	0
41	Matured Long-Term Debt (239)	0

42	Matured Interest (240)	0
43	Tax Collections Payable (241)	23757
44	Miscellaneous Current and Accrued Liabilities (242)	4245630
45	Obligations Under Capital Leases-Current (243)	0
46	Derivative Instrument Liabilities (244)	0
47	Derivative Instrument Liabilities - Hedges (245)	0
48	TOTAL Current & Accrued Liabilities (Enter Total of lines 32 thru 44)	47187857
49	DEFERRED CREDITS	0
50	Customer Advances for Construction (252)	485386
51	Accumulated Deferred Investment Tax Credits (255)	39317877
52	Deferred Gains from Disposition of Utility Plant (256)	0
53	Other Deferred Credits (253)	2715928
54	Other Regulatory Liabilities (254)	0
55	Unamortized Gain on Reaquired Debt (257)	0
56	Accumulated Deferred Income Taxes (281-283)	19581445
57	TOTAL Deferred Credits (Enter Total of lines 47 thru 53)	62100636
58		0
59		0
60		0
61		0
62		0
63		0
64		0
65		0
66		0
67		0
68		0
69		0
70		0
71	TOTAL Liab and Other Credits (Enter Total of lines 14,22,30,45,54	1227312539

row_numbe	row_literal	current_yr_total
1	UTILITY OPERATING INCOME	0
2	Operating Revenues (400)	346852831
3	Operating Expenses	0
4	Operation Expenses (401)	211354945
5	Maintenance Expenses (402)	10494687
6	Depreciation Expense (403)	15272381
7	Amort. & Depl. of Utility Plant (404-405)	4197
8	Amort. of Utility Plant Acq. Adj. (406)	0
9	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)	0
10	Amort. of Conversion Expenses (407)	0
11	Regulatory Debits (407.3)	0
12	(Less) Regulatory Credits (407.4)	0
13	Taxes Other Than Income Taxes (408.1)	24270492
14	Income Taxes - Federal (409.1)	-9020264
15	- Other (409.1)	-155527
16	Provision for Deferred Income Taxes (410.1)	16877306
17	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	0
18	Investment Tax Credit Adj. - Net (411.4)	-4434079
19	(Less) Gains from Disp. of Utility Plant (411.6)	0
20	Losses from Disp. of Utility Plant (411.7)	0
21	(Less) Gains from Disposition of Allowances (411.8)	0
22	Losses from Disposition of Allowances (411.9)	0
23	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 22)	264174925
24	Net Util Oper Inc (Enter Tot line 2 less 23) Carry fwd to P117,line 25	74637449
25	Net Utility Operating Income (Carried forward from page 114)	74637449
26	Other Income and Deductions	0
27	Other Income	0
28	Nonutilty Operating Income	0
29	Revenues From Merchandising, Jobbing and Contract Work (415)	31
30	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)	57
31	Revenues From Nonutility Operations (417)	0
32	(Less) Expenses of Nonutility Operations (417.1)	0
33	Nonoperating Rental Income (418)	8139
34	Equity in Earnings of Subsidiary Companies (418.1)	6104751
35	Interest and Dividend Income (419)	1845108
36	Allowance for Other Funds Used During Construction (419.1)	19991351
37	Miscellaneous Nonoperating Income (421)	65340
38	Gain on Disposition of Property (421.1)	8895
39	TOTAL Other Income (Enter Total of lines 29 thru 38)	28095558
40	Other Income Deductions	0
41	Loss on Disposition of Property (421.2)	916103

42	Miscellaneous Amortization (425)	0
43	Miscellaneous Income Deductions (426.1-426.5)	415740
44	TOTAL Other Income Deductions (Total of lines 41 thru 43)	1331843
45	Taxes Applic. to Other Income and Deductions	0
46	Taxes Other Than Income Taxes (408.2)	0
47	Income Taxes-Federal (409.2)	-14521
48	Income Taxes-Other (409.2)	-1962
49	Provision for Deferred Inc. Taxes (410.2)	0
50	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	0
51	Investment Tax Credit Adj.-Net (411.5)	0
52	(Less) Investment Tax Credits (420)	0
53	TOTAL Taxes on Other Income and Deduct. (Total of 46 thru 52)	-16483
54	Net Other Income and Deductions (Enter Total lines 39, 44, 53)	26780198
55	Interest Charges	0
56	Interest on Long-Term Debt (427)	50753640
57	Amort. of Debt Disc. and Expense (428)	581549
58	Amortization of Loss on Reaquired Debt (428.1)	0
59	(Less) Amort. of Premium on Debt-Credit (429)	34065
60	(Less) Amortization of Gain on Reaquired Debt-Credit (429.1)	0
61	Interest on Debt to Assoc. Companies (430)	242127
62	Other Interest Expense (431)	1682078
63	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)	19514922
64	Net Interest Charges (Enter Total of lines 56 thru 63)	33710407
65	Income Before Extraordinary Items (Total of lines 25, 54 and 64)	67707240
66	Extraordinary Items	0
67	Extraordinary Income (434)	0
68	(Less) Extraordinary Deductions (435)	0
69	Net Extraordinary Items (Enter Total of line 67 less line 68)	0
70	Income Taxes-Federal and Other (409.3)	0
71	Extraordinary Items After Taxes (Enter Total of line 69 less line 70)	0
72	Net Income (Enter Total of lines 65 and 71)	67707240

respondent_id	row_literal	amt2
-	Utility Plant	0
-	In Service	0
-	Plant in Service (Classified)	733829390
-	Property Under Capital Leases	0
-	Plant Purchased or Sold	0
-	Completed Construction not Classified	0
-	Experimental Plant Unclassified	0
-	Total (3 thru 7)	733829390
-	Leased to Others	0
-	Held for Future Use	0
-	Construction Work in Progress	395759360
-	Acquisition Adjustments	0
-	Total Utility Plant (8 thru 12)	1129588750
-	Accum Prov for Depr, Amort, & Depl	141933251
-	Net Utility Plant (13 less 14)	987655499
-	Detail of Accum Prov for Depr, Amort & Depl	0
-	In Service:	0
-	Depreciation	141828316
-	Amort & Depl of Producing Nat Gas Land/Land Right	0
-	Amort of Underground Storage Land/Land Rights	0
-	Amort of Other Utility Plant	104935
-	Total In Service (18 thru 21)	141933251
-	Leased to Others	0
-	Depreciation	0
-	Amortization and Depletion	0
-	Total Leased to Others (24 & 25)	0
-	Held for Future Use	0
-	Depreciation	0
-	Amortization	0
-	Total Held for Future Use (28 & 29)	0
-	Abandonment of Leases (Natural Gas)	0
-	Amort of Plant Acquisition Adj	0
-	Total Accum Prov (equals 14) (22,26,30,31,32)	141933251

row_number	row_literal	yr_end_bal
1	1. INTANGIBLE PLANT	0
2	(301) Organization	0
3	(302) Franchises and Consents	193079
4	(303) Miscellaneous Intangible Plant	0
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	193079
6	2. PRODUCTION PLANT	0
7	A. Steam Production Plant	0
8	(310) Land and Land Rights	516129
9	(311) Structures and Improvements	25561750
10	(312) Boiler Plant Equipment	70635396
11	(313) Engines and Engine-Driven Generators	179
12	(314) Turbogenerator Units	21491564
13	(315) Accessory Electric Equipment	11751312
14	(316) Misc. Power Plant Equipment	2394533
15	TOTAL Steam Production Plant (Enter Total of lines 8 thru 14)	132350863
16	B. Nuclear Production Plant	0
17	(320) Land and Land Rights	0
18	(321) Structures and Improvements	0
19	(322) Reactor Plant Equipment	0
20	(323) Turbogenerator Units	0
21	(324) Accessory Electric Equipment	0
22	(325) Misc. Power Plant Equipment	0
23	TOTAL Nuclear Production Plant (Enter Total of lines 17 thru 22)	0
24	C. Hydraulic Production Plant	0
25	(330) Land and Land Rights	42016210
26	(331) Structures and Improvements	19665320
27	(332) Reservoirs, Dams, and Waterways	55268908
28	(333) Water Wheels, Turbines, and Generators	42885447
29	(334) Accessory Electric Equipment	5133337
30	(335) Misc. Power PLant Equipment	2296374
31	(336) Roads, Railroads, and Bridges	911333
32	TOTAL Hydraulic Production Plant (Enter Total of lines 25 thru 31)	168176929
33	D. Other Production Plant	0
34	(340) Land and Land Rights	140863
35	(341) Structures and Improvements	561479
36	(342) Fuel Holders, Products, and Accessories	1277367
37	(343) Prime Movers	772882
38	(344) Generators	2917827
39	(345) Accessory Electric Equipment	170165
40	(346) Misc. Power Plant Equipment	327208
41	TOTAL Other Prod. Plant (Enter Total of lines 34 thru 40)	13123191
42	TOTAL Prod. Plant (Enter Total of lines 15, 23, 32, and 41)	313650983
43	3. TRANSMISSION PLANT	0
44	(350) Land and Land Rights	7347613
45	(352) Structures and Improvements	1856707
46	(353) Station Equipment	48207912
47	(354) Towers and Fixtures	3169578
48	(355) Poles and Fixtures	23158512
49	(356) Overhead Conductors and Devices	26694146
50	(357) Underground Conduit	373362
51	(358) Underground Conductors and Devices	595577
52	(359) Roads and Trails	52905
53	TOTAL Transmission Plant (Enter Total of lines 44 thru 52)	111456312
54	4. DISTRIBUTION PLANT	0
55	(360) Land and Land Rights	2495137
56	(361) Structures and Improvements	4331685
57	(362) Station Equipment	37251639
58	(363) Storage Battery Equipment	0

59	(364) Poles, Towers, and Fixtures	55599702
60	(365) Overhead Conductors and Devices	39259069
61	(366) Underground Conduit	5488903
62	(367) Underground Conductors and Devices	18646927
63	(368) Line Transformers	52841899
64	(369) Services	25479523
65	(370) Meters	10687064
66	(371) Installations on Customer Premises	0
67	(372) Leased Property on Customer Premises	0
68	(373) Street Lighting and Signal Systems	6829203
69	TOTAL Distribution Plant (Enter Total of lines 55 thru 68)	258910751
70	5. GENERAL PLANT	0
71	(389) Land and Land Rights	1251948
72	(390) Structures and Improvements	21448452
73	(391) Office Furniture and Equipment	9416982
74	(392) Transportation Equipment	6657210
75	(393) Stores Equipment	243166
76	(394) Tools, Shop and Garage Equipment	1214786
77	(395) Laboratory Equipment	542841
78	(396) Power Operated Equipment	4639995
79	(397) Communication Equipment	4064070
80	(398) Miscellaneous Equipment	138815
81	SUBTOTAL (Enter Total of lines 71 thru 80)	49618265
82	(399) Other Tangible Property	0
83	TOTAL General Plant (Enter Total of lines 81 and 82)	49618265
84	TOTAL (Accounts 101 and 106)	0
85	(102) Electric Plant Purchased (See Instr. 8)	0
86	(Less) (102) Electric Plant Sold (See Instr. 8)	0
87	(103) Experimental Plant Unclassified	0
88	TOTAL Electric Plant in Service (Enter Total of lines 84 thru 87)	733829390

row_number	row_literal	electric_plant
1	Balance Beginning of Year	131521897
2	Depreciation Provisions for Year, Charged to	0
3	(403) Depreciation Expense	13748267
4	(413) Exp. of Elec. Plt. Leas. to Others	0
5	Transportation Expenses-Clearing	625117
6	Other Clearing Accounts	0
7	Other Accounts (Specify, details in footnote):	439425
8		0
9	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 8)	14812809
10	Net Charges for Plant Retired:	0
11	Book Cost of Plant Retired	4594425
12	Cost of Removal	1195667
13	Salvage (Credit)	1361960
14	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 11 thru 13)	4428132
15	Other Debit or Cr. Items (Describe, details in footnote):	2546
16		-80804
17	Balance End of Year (Enter Totals of lines 1, 9, 14, 15, and 16)	141828316
18	Steam Production	14758596
19	Nuclear Production	0
20	Hydraulic Production-Conventional	21829684
21	Hydraulic Production-Pumped Storage	0
22	Other Production	2984614
23	Transmission	25452430
24	Distribution	64123130
25	General	12679862
26	TOTAL (Enter Total of lines 18 thru 25)	141828316

row_number	row_seq	spplmnt_n	row_lit	row_prvlg
1	1	0	Line 1	N
2	2	0	Line 2	N
3	3	0	Line 3	N
4	4	0	Line 4	N
5	5	0	Line 5	N
6	6	0	Line 6	N
7	7	0	Line 7	N
8	8	0	Line 8	N
9	9	0	Line 9	N
10	10	0	Line 10	N
11	11	0	Line 11	N
12	12	0	Line 12	N
13	13	0	Line 13	N
14	14	0	Line 14	N
15	15	0	Line 15	N
16	16	0	Line 16	
17	17	0	Line 17	N
18	18	0	Line 18	N
19	19	0	Line 19	N
20	20	0	Line 20	
21	21	0	Line 21	N
22	22	0	Line 22	N
23	23	0	Line 23	N
24	24	0	Line 24	
25	25	0	Line 25	N
26	26	0	Line 26	N
27	27	0	Line 27	N
28	28	0	Line 28	
29	29	0	Line 29	N
30	30	0	Line 30	N
31	31	0	Line 31	N
32	32	0	Line 32	N
33	33	0	Line 33	N
34	34	0	Line 34	N
35	35	0	Line 35	N
36	36	0	Line 36	
37	37	0	Line 37	N
38	38	0	Line 38	N
39	39	0	Line 39	N
40	40	0	Line 40	N
41	41	0	Line 41	N
42	42	0	Line 42	N
43	43	0	Line 43	N

row_number	dfrrd_debit_dsc	yr_end_bal
1	Misc. undistributed charges	0
2	(9 items)	144462
3		0
4	Water Heater Insulation	0
5	Blankets - WA (3 years)	0
6		0
7	Water Heater Insulation	0
8	Blankets - ID (3 years)	0
9		0
10	Company Home Sale Plan for	0
11	Managers' Relocation (13 items)	276525
12		0
13	Residential Purchase and Sale	0
14	Agreement - BPA	50644
15		0
16	Southern CA Edison Co.	1081568
17		0
18	Weatherization Grants (6-9 years)	11497471
19		0
20	Undelivered Coal-WIDCo	928446
21		0
22	Street Light Change	0
23	Washington	-395993
24		0
25	Street Light Change	0
26	Idaho	-118533
27		0
28	Return of Ratepayer Contributions	0
29	in Excess of Refund - Gas	0
30	Exploration Advance	118124
31		0
32	Investment in Terminated Nuclear	0
33	Project (Skagit)	39339840
34		0
35		0
36		0
37		0
38		0
39		0
40		0
41		0
42		0

43		0
44		0
45		0
46		0
	Misc Work in Progress	621954
	Deferred Regulatory Commission Expenses	24

row_number	cls_sers_oblgt	prncpl_amt_(	total_expen	premium_(	nominal_iss_d	maturity_date	amrtzdper_dt	amrtzdper_d	outstanding	yr_amt_intrst	total_exper	col_disp
29												
30	SUBTOTAL Account 221								410135000	33568997		
31												
7												
8	SUBTOTAL Account 224								157461121	17184643		
9									567596121	50753640		

tax_kind	tax_paid_drng_yr
Federal:	0
FERC Resale/Coord Charges	0
Income Tax	-43334
FICA (Employer share)	0
Unemployment Compensation	78339
Ins. Contr. Act	2413895
Use Tax - Mtr. Vehicle	14376
Subtotal Federal	2463276
State of Montana:	0
Income Tax	185621
Elec. Energy Producers Tax	83352
Unemployment Insurance	1105283
Motor Vehicle	636
Property Taxes	2943923
Subtotal Montana	3477325
State of Washington:	0
Property Taxes	3222396
Excise Tax	9612545
Unemploy. Ins.	397074
Motor Vehicle	120786
Subtotal Washington	13352801
Idaho	0
Income Taxes	620022
Property Taxes	1116777
kWh tax	366090
Unemploy. Tax	46858
Excise Tax	13836
Motor Vehicle	9948
Mileage Use	1863
Subtotal Idaho	2175394
County & Municipal	0
Occupation	6032319
Real Estate	34650
Use of Streets	25225
Paving Assessment	3868
Spokane Bus. Lic.	10630
Subtotal County & Muni	6106692
Canada Income Tax	2659

row_number	othr_dfr_cr_dsc	yr_end_bal
1	Unearned interest -	0
2	Customer wiring and installation contracts	94609
3		0
4	Water amortization -	0
5	Plant in Service	0
6		0
7	Gas Exploration Advance -	0
8	Develop Assoc Inc.	0
9		0
10	Gas Refund - WA	1325919
11		0
12	Gas Refund - ID	282041
13		0
14	Accum. Credits Allowed under	0
15	BPA Res Exchange	0
16	Agreement WA	-147087
17		0
18	BPA Conservation Program	0
19	Excess Reimbursement	1128979
20		0
21	Deferred Compensation	31467
22		0
23		
24		
25		
26		
27		
28		
29		
30		
31		
32		
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35		
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41		
42		

row_numbe	row_lit	row_prvlg	dsc_purp
1	Line 1		
2	Line 2		
3	Line 3		
4	Line 4		
5	Line 5		
6	Line 6		
7	Line 7		
8	Line 8		
9	Line 9		
10	Line 10		
11	Line 11		
12	Line 12		
13	Line 13		
14	Line 14		
15	Line 15		
16	Line 16		
17	Line 17		
18	Line 18		
19	Line 19		
20	Line 20		
21	Line 21		
22	Line 22		
23	Line 23		
24	Line 24		
25	Line 25		
26	Line 26		
27	Line 27		
28	Line 28		
29	Line 29		
30	Line 30		
31	Line 31		
32	Line 32		
33	Line 33		
34	Line 34		
35	Line 35		
36	Line 36		
37	Line 37		
38	Line 38		
39	Line 39		
40	Line 40		

row_numbe	row_literal	rev_amt_crnt_yr	mwh_sold_crnt_yr
1	Sales of Electricity	0	0
2	(440) Residential Sales	86527710	2911547
3	(442) Commercial and Industrial Sales	0	0
4	Small (or Comm.) (See Instr. 4)	56065647	1679181
5	Large (or Ind.) (See Instr. 4)	26886839	1349331
6	(444) Public Street and Highway Lighting	2526061	30387
7	(445) Other Sales to Public Authorities	0	0
8	(446) Sales to Railroads and Railways	0	0
9	(448) Interdepartmental Sales	0	0
10	TOTAL Sales to Ultimate Consumers	172006257	5970446
11	(447) Sales for Resale	40873753	3006924
12	TOTAL Sales of Electricity	212880010	8977370
13	(Less) (449.1) Provision for Rate Refunds	0	0
14	TOTAL Revenues Net of Prov. for Refunds	0	8977370
15	Other Operating Revenues	0	0
16	(450) Forfeited Discounts	0	0
17	(451) Miscellaneous Service Revenues	83682	0
18	(453) Sales of Water and Water Power	390654	0
19	(454) Rent from Electric Property	705060	0
20	(455) Interdepartmental Rents	0	0
21	(456) Other Electric Revenues	1391326	0
22	(See footnote to Account 456, Other Electric Rev.)	0	0
23		0	0
24		0	0
25		0	0
26	TOTAL Other Operating Revenues	2570722	0
27	TOTAL Electric Operating Revenues	215450732	0

row_number	tot_revenue_chgs
Total	40873753

row_numbe	row_seq	row_literal	crnt_yr_amt
1	1	1. POWER PRODUCTION EXPENSES	0
2	2	A. Steam Power Generation	0
3	3	Operation	0
4	4	(500) Operation Supervision and Engineering	275137
5	5	(501) Fuel	16201634
6	6	(502) Steam Expenses	273504
7	7	(503) Steam from Other Sources	0
8	8	(Less) (504) Steam Transferred-Cr.	0
9	9	(505) Electric Expenses	197006
10	10	(506) Miscellaneous Steam Power Expenses	500106
11	11	(507) Rents	4646
12	12	(509) Allowances	0
13	13	TOTAL Operation (Enter Total of Lines 4 thru 12)	17452033
14	14	Maintenance	0
15	15	(510) Maintenance Supervision and Engineering	309248
16	16	(511) Maintenance of Structures	189019
17	17	(512) Maintenance of Boiler Plant	1448451
18	18	(513) Maintenance of Electric Plant	222498
19	19	(514) Maintenance of Miscellaneous Steam Plant	181716
20	20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	2350932
21	21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	19802965
22	22	B. Nuclear Power Generation	0
23	23	Operation	0
24	24	(517) Operation Supervision and Engineering	0
25	25	(518) Fuel	0
26	26	(519) Coolants and Water	0
27	27	(520) Steam Expenses	0
28	28	(521) Steam from Other Sources	0
29	29	(Less) (522) Steam Transferred-Cr.	0
30	30	(523) Electric Expenses	0
31	31	(524) Miscellaneous Nuclear Power Expenses	0
32	32	(525) Rents	0
33	33	TOTAL Operation (Enter Total of lines 24 thru 32)	0
34	34	Maintenance	0
35	35	(528) Maintenance Supervision and Engineering	0
36	36	(529) Maintenance of Structures	0
37	37	(530) Maintenance of Reactor Plant Equipment	0
38	38	(531) Maintenance of Electric Plant	0
39	39	(532) Maintenance of Miscellaneous Nuclear Plant	0
40	40	TOTAL Maintenance (Enter Total of lines 35 thru 39)	0
41	41	TOTAL Power Production Expenses-Nuc. Power (Entr tot lines 33 & 40)	0
42	42	C. Hydraulic Power Generation	0

43	43 Operation	0
44	44 (535) Operation Supervision and Engineering	901447
45	45 (536) Water for Power	161500
46	46 (537) Hydraulic Expenses	82839
47	47 (538) Electric Expenses	1287526
48	48 (539) Miscellaneous Hydraulic Power Generation Expenses	302966
49	49 (540) Rents	21634
50	50 TOTAL Operation (Enter Total of Lines 44 thru 49)	2757912
51	51 C. Hydraulic Power Generation (Continued)	0
52	52 Maintenance	0
53	53 (541) Mainentance Supervision and Engineering	97845
54	54 (542) Maintenance of Structures	83836
55	55 (543) Maintenance of Reservoirs, Dams, and Waterways	338918
56	56 (544) Maintenance of Electric Plant	561081
57	57 (545) Maintenance of Miscellaneous Hydraulic Plant	33163
58	58 TOTAL Maintenance (Enter Total of lines 53 thru 57)	1114843
59	59 TOTAL Power Production Expenses-Hydraulic Power (tot of lines 50 & 58)	3872755
60	60 D. Other Power Generation	0
61	61 Operation	0
62	62 (546) Operation Supervision and Engineering	2957
63	63 (547) Fuel	239407
64	64 (548) Generation Expenses	30637
65	65 (549) Miscellaneous Other Power Generation Expenses	4752
66	66 (550) Rents	0
67	67 TOTAL Operation (Enter Total of lines 62 thru 66)	277753
68	68 Maintenance	0
69	69 (551) Maintenance Supervision and Engineering	814
70	70 (552) Maintenance of Structures	322
71	71 (553) Maintenance of Generating and Electric Plant	16083
72	72 (554) Maintenance of Miscellaneous Other Power Generation Plant	4614
73	73 TOTAL Maintenance (Enter Total of lines 69 thru 72)	21833
74	74 TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	299586
75	75 E. Other Power Supply Expenses	0
76	76 (555) Purchased Power	51871714
77	77 (556) System Control and Load Dispatching	489506
78	78 (557) Other Expenses	41564
79	79 TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	52402784
80	80 TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	76378090
81	81 2. TRANSMISSION EXPENSES	0
82	82 Operation	0
83	83 (560) Operation Supervision and Engineering	156826
84	84 (561) Load Dispatching	163247
85	85 (562) Station Expenses	381893

86	86	(563) Overhead Lines Expenses	73562
87	87	(564) Underground Lines Expenses	122
88	88	(565) Transmission of Electricity by Others	4401232
89	89	(566) Miscellaneous Transmission Expenses	68179
90	90	(567) Rents	5900
91	91	TOTAL Operation (Enter Total of lines 83 thru 90)	5250961
92	92	Maintenance	0
93	93	(568) Maintenance Supervision and Engineering	68568
94	94	(569) Maintenance of Structures	6277
95	95	(570) Maintenance of Station Equipment	344468
96	96	(571) Maintenance of Overhead Lines	303939
97	97	(572) Maintenance of Underground Lines	33317
98	98	(573) Maintenance of Miscellaneous Transmission Plant	4962
99	99	TOTAL Maintenance (Enter Total of lines 93 thru 98)	761531
100	100	TOTAL Transmission Expenses (Enter Total of lines 91 and 99)	6012492
101	101	3. DISTRIBUTION EXPENSES	0
102	102	Operation	0
103	103	(580) Operation Supervision and Engineering	313711
104	104	3. DISTRIBUTION Expenses (Continued)	0
105	105	(581) Load Dispatching	65174
106	106	(582) Station Expenses	501005
107	107	(583) Overhead Line Expenses	515487
108	108	(584) Underground Line Expenses	203136
109	109	(585) Street Lighting and Signal System Expenses	145466
110	110	(586) Meter Expenses	431557
111	111	(587) Customer Installations Expenses	266811
112	112	(588) Miscellaneous Expenses	415977
113	113	(589) Rents	35090
114	114	TOTAL Operation (Enter Total of lines 103 thru 113)	2893414
115	115	Maintenance	0
116	116	(590) Maintenance Supervision and Engineering	243802
117	117	(591) Maintenance of Structures	19807
118	118	(592) Maintenance of Station Equipment	282277
119	119	(593) Maintenance of Overhead Lines	2168189
120	120	(594) Maintenance of Underground Lines	400622
121	121	(595) Maintenance of Line Transformers	272355
122	122	(596) Maintenance of Street Lighting and Signal Systems	120845
123	123	(597) Maintenance of Meters	96631
124	124	(598) Maintenance of Miscellaneous Distribution Plant	11826
125	125	TOTAL Maintenance (Enter Total of lines 116 thru 124)	3616354
126	126	TOTAL Distribution Exp (Enter Total of lines 114 and 125)	659768
127	127	4. CUSTOMER ACCOUNTS EXPENSES	0
128	128	Operation	0

129	129 (901) Supervision	242086
130	130 (902) Meter Reading Expenses	1573660
131	131 (903) Customer Records and Collection Expenses	3355559
132	132 (904) Uncollectible Accounts	1287792
133	133 (905) Miscellaneous Customer Accounts Expenses	49417
134	134 TOTAL Customer Accounts Expenses (Total of lines 129 thru 133)	6508514
135	135 5. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES	0
136	136 Operation	0
137	137 (907) Supervision	153720
138	138 (908) Customer Assistance Expenses	2568580
139	139 (909) Informational and Instructional Expenses	152742
140	140 (910) Miscellaneous Customer Service and Informational Expenses	66786
141	141 TOTAL Cust. Service and Information. Exp. (Total lines 137 thru 140)	2941828
142	142 6. SALES EXPENSES	0
143	143 Operation	0
144	144 (911) Supervision	35096
145	145 (912) Demonstrating and Selling Expenses	96665
146	146 (913) Advertising Expenses	0
147	147 (916) Miscellaneous Sales Expenses	3241
148	148 TOTAL Sales Expenses (Enter Total of lines 144 thru 147)	135002
149	149 7. ADMINISTRATIVE AND GENERAL EXPENSES	0
150	150 Operation	0
151	151 (920) Administrative and General Salaries	3597282
152	152 (921) Office Supplies and Expenses	1121720
153	153 (Less) (922) Administrative Expenses Transferred-Credit	327776
154	154 7. ADMINISTRATIVE AND GENERAL EXPENSES (Continued)	0
155	155 (923) Outside Services Employed	826421
156	156 (924) Property Insurance	172418
157	157 (925) Injuries and Damages	926748
158	158 (926) Employee Pensions and Benefits	4719169
159	159 (927) Franchise Requirements	711121
160	160 (928) Regulatory Commission Expenses	1582177
161	161 (929) (Less) Duplicate Charges-Cr.	0
162	162 (930.1) General Advertising Expenses	49516
163	163 (930.2) Miscellaneous General Expenses	2247716
164	164 (931) Rents	587813
165	165 TOTAL Operation (Enter Total of lines 151 thru 164)	16214325
166	166 Maintenance	0
167	167 (935) Maintenance of General Plant	871318
168	168 TOTAL Admin & General Expenses (Total of lines 165 thru 167)	17085643
169	169 TOTAL Elec Op and Maint Expn (Tot 80, 100, 126, 134, 141, 148, 168)	115571337

row_number	row_literal	mwh_purchased	settlement_tot
	Total	4235750	51867515

row_number	tot_revenues
1	630062
2	62108
3	1208
4	41961
5	52919
6	25824
7	10116
8	18233
9	3138
10	85630
11	5810
12	3198
13	400
14	300
15	172200
16	416354
17	674580
1	91569
2	26059
3	82838
4	61026
5	13616
6	55161
7	7330
8	568512
9	400348
10	459540
11	3231
12	188
13	2710
14	88000
15	0
16	0
17	0
1	0
2	0
3	0
4	0
5	0
6	0
7	0
8	0

9	0
10	0
11	0
12	0
13	0
14	0
15	0
16	0
17	0
	4064169

row_number	row_literal	total
1	Intangible Plant	0
2	Steam Production Plant	1668885
3	Nuclear Production Plant	0
4	Hydraulic Production Plant-Conventional	1234485
5	Hydraulic Production Plant-Pumped Storage	0
6	Other Production Plant	522782
7	Transmission Plant	2234374
8	Distribution Plant	6789895
9	General Plant	1302043
10	Common Plant-Electric	0
11	TOTAL	13752464

row_numbe	row_literal	drct_pyrl_dstrbt
1	Electric	0
2	Operation	0
3	Production	2751624
4	Transmission	630328
5	Distribution	2464287
6	Customer Accounts	3982136
7	Customer Service and Informational	1533093
8	Sales	104830
9	Administrative and General	4509799
10	TOTAL Operation (Enter Total of lines 3 thru 9)	15976097
11	Maintenance	0
12	Production	607306
13	Transmission	338689
14	Distribution	2220830
15	Administrative and General	359285
16	TOTAL Maint. (Total of lines 12 thru 15)	3526110
17	Total Operation and Maintenance	0
18	Production (Enter Total of lines 3 and 12)	3358930
19	Transmission (Enter Total of lines 4 and 13)	969017
20	Distribution (Enter Total of lines 5 and 14)	4685117
21	Customer Accounts (Transcribe from line 6)	3982136
22	Customer Service and Informational (Transcribe from line 7)	1533093
23	Sales (Transcribe from line 8)	104830
24	Administrative and General (Enter Total of lines 9 and 15)	4869084
25	TOTAL Oper. and Maint. (Total of lines 18 thru 24)	19502207
26	Gas	0
27	Operation	0
28	Production-Manufactured Gas	0
29	Production-Nat. Gas (Including Expl. and Dev.)	0
30	Other Gas Supply	106315
31	Storage, LNG Terminaling and Processing	0
32	Transmission	0
33	Distribution	803927
34	Customer Accounts	1287803
35	Customer Service and Informational	242110
36	Sales	36329
37	Administrative and General	1414392
38	TOTAL Operation (Enter Total of lines 28 thru 37)	3890876
39	Maintenance	0
40	Production-Manufactured Gas	0
41	Production-Natural Gas	0
42	Other Gas Supply	0

43	Storage, LNG Terminaling and Processing	0
44	Transmission	0
45	Distribution	285413
46	Administrative and General	29110
47	TOTAL Maint. (Enter Total of lines 40 thru 46)	314523
48	Total Operation and Maintenance	0
49	Production-Manufactured Gas (Enter Total of lines 28 and 40)	0
50	Production-Natural Gas (Including Expl. and Dev.) (Total lines 29, 41)	0
51	Other Gas Supply (Enter Total of lines 30 and 42)	106315
52	Storage, LNG Terminaling and Processing (Total of lines 31 thru 43)	0
53	Transmission (Lines 32 and 44)	0
54	Distribution (Lines 33 and 45)	1089340
55	Customer Accounts (Line 34)	1287803
56	Customer Service and Informational (Line 35)	242110
57	Sales (Line 36)	36329
58	Administrative and General (Lines 37 and 46)	1443502
59	TOTAL Operation and Maint. (Total of lines 49 thru 58)	4205399
60	Other Utility Departments	0
61	Operation and Maintenance	336183
62	TOTAL All Utility Dept. (Total of lines 25, 59, and 61)	24043789
63	Utility Plant	0
64	Construction (By Utility Departments)	0
65	Electric Plant	9340616
66	Gas Plant	701980
67	Other	56412
68	TOTAL Construction (Total of lines 65 thru 67)	10099008
69	Plant Removal (By Utility Departments)	0
70	Electric Plant	540249
71	Gas Plant	17943
72	Other	14730
73	TOTAL Plant Removal (Total of lines 70 thru 72)	572922
74	Other Accounts (Specify):	0
75		0
76		0
77		0
78		0
79		0
80		0
81		0
82		0
83		0
84		0
85		0

86		0
87		0
88		0
89		0
90		0
91		0
92		0
93		0
94		0
95	TOTAL Other Accounts	3601095
96	TOTAL SALARIES AND WAGES	38316814

		Washington	Idaho	Total
	Contract System Cost:			
1	Production Cost	63,274	38,766	102,040
2	Transmission Cost	14,853	8,856	23,709
3	Less: Excluded Load Cost	0	0	0
4	Total Contract System Cost	78,127	47,622	125,749
	Contract System Load:			
5	Total Load (MWH)	3,816,842	2,126,716	5,943,558
	Less:			
6	Nonfirm Adjustment (MWH)	0	0	0
7	Other Adjustments (MWH)	0	0	0
8	Net Load (MWH)	3,816,842	2,126,716	5,943,558
	Plus:			
9	Distribution Losses (MWH)	345,843	159,175	505,018
10	Total Net Load (MWH)	4,162,685	2,285,891	6,448,576
	Less			
11	Excluded Load (MWH)	0	0	0
12	Excluded Load Distribution Losses (MWH)	0	0	0
13	Total Contract System Load (MWH)	4,162,685	2,285,891	6,448,576
14	Average System Cost (mills/kWh) (line 4/line 13	$ 18.77	$ 20.83	$ 19.50

Avista Filed ASC

Washington Water Power
RESIDENTIAL PURCHASE AND SALE AGREEMENT
Jurisdiction: Idaho
Average System Cost Methodology
Test Period: 1-1-83/12-1-83
Filing # 9-83-8581
Plant Investment/Rate Base/Rate-of-Return
(Thousands)

Line No.	Items	Functionalization: Total To Be Functionalized	Production	Transmission	Distribution/ Other
	(1)	(2)	(3)	(4)	(5)
	Production Plant:				
1	Steam Production 310-316	93,065	93,065	0	0
2	Nuclear Production 320-325	0	0	0	0
3	Hydraulic Production 330-336	59,707	59,707	0	0
4	Other Production Plant 340-346	4,659	4,659	0	0
5	Total Production Plant	157,431	157,431	0	0
6	Transmission Plant 350-359 a/	51,036	0	51,036	0
7	Distribution Plant 360-373 b/	79,831	0	0	79,831
8	Intangible Plant 301-303 i/	69	69	0	0
9	General Plant 389-399 i/	12,748	4,804	2,530	5,415
10	Electric Plant-in-Service	301,115	162,304	53,566	85,246
	LESS:				
	Depreciation & Amortization Reserve 108				
11	Steam Plant	8,006	8,006	0	0
12	Nuclear Plant	0	0	0	0
13	Hydraulic Plant	7,019	7,019	0	0
14	Other Plant	1,869	1,869	0	0
15	Transmission Plant a/	9,374	0	9,374	0
16	Distribution Plant b/	19,917	0	0	19,917
17	General Plant i/	3,057	1,152	607	1,298
18	Amortization Reserve 111 i/	38	38	0	0
19	Total Depreciation & Amortization	49,280	18,084	9,981	21,215
20	TOTAL NET PLANT	251,835	144,220	43,585	64,038

Washington Water Power
RESIDENTIAL PURCHASE AND SALE AGREEMENT
Jurisdiction Idaho
Average System Cost Methodology
Test Period 1-1-83/12-1-83
Filing # 9-A3-8581
Expenses
(Thousands)

Line No.	Items	Total To Be Functionalized	Production	Transmission	Distribution/ Other
		Functionalization			
	(1)	(2)	(3)	(4)	(5)
	Production:				
1	Fuel 501,518,547	8,892	8,892	0	0
2	Purchased Power 555	15,361	15,361	0	0
	Operations & Maintenance				
3	Steam 500, 502-514	2,469	2,469	0	0
4	Nuclear 517,519-532	0	0	0	0
5	Hydro 535-545	1,521	1,521	0	0
6	Other 546,548-554,556-557	214	214	0	0
7	Total Production Expense	28,457	28,457	0	0
8	Transmission 560-573 a/	3,725	0	3,725	0
9	Distribution 580-598 b/	1,985	0	0	1,985
10	Customer Accounting 901-905 i/	1,614	0	0	1,614
11	Customer Assistance 907-910 i/	840	0	0	840
12	Sales Expense 911-916	44	0	0	44
	Administrative & General i/				
13	920 Admin & General Salaries	1,016	216	62	737
14	921 Office Supplies & Expenses	343	73	21	249
15	922 Admin Expenses transferred - Cr.	(93)	(20)	(6)	(67)
16	923 Outside Services Employed	233	50	14	169
17	924 Property Insurance	49	27	9	14
18	925 Injuries & Damages	177	38	11	128
19	926 Employee Pensions & Benefits	1,556	332	96	1,129
20	927 Franchise Requirements	0	0	0	0
21	928 Regulatory Commission Expenses	574	0	0	574
22	929 Duplicate Charges - Cr.	0	0	0	0
23	930.1 General Advertising Expenses	252	0	0	252
24	930.2 Miscellaneous General Expenses	0	0	0	0
25	931 Rents	169	0	0	169
26	932 Maintance of General Plant	242	112	36	94
27					
28	Total A & G	4,518	825	243	3,447
29					
30	Total Operations & Maintenance	41,183	29,285	3,968	7,930

Washington Water Power
RESIDENTIAL PURCHASE AND SALE AGREEMENT
Jurisdiction: Idaho
Average System Cost Methodology
Test Period: 1-1-83/12-1-83
Filing # 9-A3-8501
Taxes Other Than Income Taxes
(Thousands)

Line No.	Items	Total To Be Functionalized	Production	Transmission	Distribution/ Other
		Functionalization			
	(1)	(2)	(3)	(4)	(5)
1	FEDERAL - Insurance Contributions	464	95	29	337
2	- Unemployment	15	3	1	11
3	- Income Tax	11,800	0	0	11,800
4	In-Lieu Tax	0	0	0	0
5	Other Tax	0	0	0	0
6	State Of: Idaho				
7	-State Income Taxes	107	0	0	107
8	-State Property Tax	2,450	1,330	434	678
9	-State Unemp. Tax	85	10	5	62
10	-State Reg. Commis. Tax	0	0	0	0
11	-State Generating Tax	290	0	0	290
12	-State Pollution Control Tax	0	0	0	0
13	-State Rev. & Business Tax	0	0	0	0
14	-Local Occupation & Franchise	0	0	0	0
15	-Excise	2	0	0	2
16	-	0	0	0	0
17	-	0	0	0	0
18	State Of: Montana				
19	-State Income Taxes	(10)	0	0	(10)
20	-State Property Tax	0	0	0	0
21	-State Unemp. Tax	0	0	0	0
22	-State Reg. Commis. Tax	0	0	0	0
23	-State Generating Tax	0	0	0	0
24	-State Pollution Control Tax	0	0	0	0
25	-State Rev. & Business Tax	0	0	0	0
26	-Local Occupation & Franchise	0	0	0	0
27	-	0	0	0	0
28	-	0	0	0	0
29	-	0	0	0	0
30	TOTAL	15,203	1,458	469	13,276

Washington Water Power
RESIDENTIAL PURCHASE AND SALE AGREEMENT
Jurisdiction: Idaho
Average System Cost Methodology
Test Period: 1-1-83/12-31-83
Filing # 9-83-8581
Average System Cost
(Thousands)

Line No.	ITEMS	AMOUNTS
	(1)	(2)
	Contract System Cost:	
1	Production Cost (From Schedule 3)	38,766
2	Transmission Cost (From Schedule 3)	8,856
3	Less: Excluded Load Costs	(0)
4	Total Contract System Costs	47,622
	Contract System Load:	
5	Total Load (MWh)	2,126,716
	Less:	
6	Nonfirm Adjusment (MWh)	(0)
7	Other Adjustments (MWh)	(0)
8	Net Load (MWh)	2,126,716
	Plus:	
9	Distribution Losses (MWh) a/	159,175
10	Total Net Load (MWh)	2,285,891
	Less:	
11	Excluded Load (MWh) f/	(0)
12	Excluded Load Distribution Losses (MWh)	(0)
13	Total Contract System Load (MWh)	2,285,891
14	Average System Cost (~~mills~~/kWh) (Line 4 / Line 13)	20.83

Washington Water Power
Jurisdiction Idaho
RESIDENTIAL PURCHASE AND SALE AGREEMENT
Average System Cost Methodology
Test Period 1-1-83/12-1-83
Filing # 9-A3-8581
Calculation of Ratios
(Thousands)

Line No.	RATIOS	Ratio Used	Total To Be Functionalized	Production	Transmission	Distribution
(GP)	RATIO OF GENERAL PLANT ACCOUNTS	Ratio Used				
1.	A/C 389 Land & Land Rights	PTD/10%	423	231	75	117
2.	A/C 390 Structures & Improvements	PTD/10%	5,218	2,850	923	1,445
3.	A/C 391 Office Furniture	LABOR/10%	2,276	485	140	1,651
4.	A/C 392 Transportation Equipment	TD/10%	1,539	0	600	939
5.	A/C 393 Stores Equipment	PTD	49	27	9	14
6.	A/C 394 Tools, Shop & Garage Equipment	PTD	220	120	39	61
7.	A/C 395 Labratory Equipment	PTD	101	55	18	28
8.	A/C 396 Power Operated Equipment	TD	1,001	0	390	611
9.	A/C 397 Communications Equipment	PTD	1,896	1,036	336	525
10.	A/C 398 Miscellaneous Equipment	DIST	25	0	0	25
11.	A/C 399 Other Tangible Property	PTD	0	0	0	0
12.	TOTAL		12,748	4,804	2,530	5,415
13.	RATIO (GP)		100.00%	37.68%	19.85%	42.47%

Line No.	RATIOS	Total To Be Functionalized	Production	Transmission	Distribution
(PTD)	RATIO OF PRODUCTION, TRANSMISSION, DISTRIBUTION PLANT				
	PRODUCTION PLANT				
14.	Steam Production 310-316	93,065	93,065	0	0
15.	Nuclear Production 320-325	0	0	0	0
16.	Hydraulic Production 330-336	59,707	59,707	0	0
17.	Other Production Plant 340-346	4,659	4,659	0	0
18.	Total Production Plant	157,431	157,431	0	0
19.	Transmission Plant 350-359	51,036	0	51,036	0
20.	Distribution Plant 360-373	79,831	0	0	79,831
21.	Intangible Plant 301-303	69	69	0	0
22.	TOTAL	288,367	157,500	51,036	79,831
	RATIO (PTD = PLANT IN SERVICE)	100.00%	54.62%	17.70%	27.68%

Line No.	RATIOS		Total To Be Functionalized	Production	Transmission	Distribution
(LABOR)	RATIO OF LABOR					
43.	Production 500-557	(Labor Only)	1,203	1,203	0	0
44.	Transmission 560-573	(")	347	0	347	0
45.	Distribution 580-598	(")	1,194	0	0	1,194
46.	Customer Account 901-905	(")	0	0	0	0
47.	Customer Service 907-910	(")	1,540	0	0	1,540
48.	Sales Expense 911-916	(")	0	0	0	0
49.	Admin. & General 920-932	(")	1,362	0	0	1,362
50.	TOTAL		5,646	1,203	347	4,096
51.	RATIO (LABOR)		100.00%	21.31%	6.15%	72.55%

Schedule CWC
Report - Final

Schedule CWC

Washington Water Power
RESIDENTIAL PURCHASE AND SALE AGREEMENT
Jurisdiction Idaho
Average System Cost Methodology
Test Period 1-1-83/12-1-83
Filing # 9-A3-8501
Cash Working Capital
(Thousands)

Line No.	Items	Total To Be Functionalized	Functionalization Production	Transmission	Distribution
	(1)	(2)	(3)	(4)	(5)
1	Production O&M	28,457	28,457	0	0
2	Transmission O&M	3,725	0	3,725	0
3	Distribution O&M	1,985	0	0	1,985
4	Customer Accounting Exps	1,614	0	0	1,614
5	Customer Service Exps	840	0	0	840
6	Administrative & General Exps	4,518	828	243	3,447
7	Less Purchased Power & Fuel Costs	(24,253)	(24,253)	0	0
8	Total O&M Expenses	16,886	5,032	3,968	7,886
9	One Eighth O&M Expenses	2,111	629	496	986
10	Add: Purchased Power Costs *	0			0
11	Functionalized Cash Working Capital	2,111	629	496	986

* Any Amount of Purchase Power that is included in the calculation of Cash Working Capital is functionalized to Distribution.

Washington Water Power Company
RESIDENTIAL PURCHASE AND SALE AGREEMENT
Jurisdiction: Washington
Average System Cost Methodology
Test Period: 1-1-83/12-1-83
Filing # 9-A2-8501
Plant Investment/Rate Base/Rate-of-Return
(Thousands)

Line No.	Items	Total To Be Functionalized	Functionalization: Production	Transmission	Distribution/Other
	(1)	(2)	(3)	(4)	(5)
	Production Plant:				
1	Steam Production 310-316	144,688	144,688	0	0
2	Nuclear Production 320-325	0	0	0	0
3	Hydraulic Production 330-336	101,008	101,008	0	0
4	Other Production Plant 340-346	7,885	7,885	0	0
5	Total Production Plant	253,581	253,581	0	0
6	Transmission Plant 350-359 a/	82,508	0	82,508	0
7	Distribution Plant 360-373 b/	170,298	0	0	170,298
8	Intangible Plant 301-303 i/	116	116	0	0
9	General Plant 389-399 i/	23,527	7,838	4,364	11,326
10	Electric Plant-in-Service	530,030	261,535	86,872	181,624
	LESS:				
	Depreciation & Amortization Reserve 108				
11	Steam Plant	10,380	10,380	0	0
12	Nuclear Plant	0	0	0	0
13	Hydraulic Plant	12,735	12,735	0	0
14	Other Plant	1,663	1,663	0	0
15	Transmission Plant a/	15,312	0	15,312	0
16	Distribution Plant b/	42,561	0	0	42,561
17	General Plant i/	6,008	2,001	1,114	2,892
18	Amortization Reserve 111 i/	61	61	0	0
19	Total Depreciation & Amortization	88,720	26,840	16,426	45,453
20	TOTAL NET PLANT	441,310	234,694	70,445	136,170

Washington Water Power Company
RESIDENTIAL PURCHASE AND SALE AGREEMENT
JurisdictionWashington
Average System Cost Methodology
Test Period 1-1-83/12-1-83
Filing # 9-A2-8501
Expenses
(Thousands)

Line No.	Items	Total To Be Functionalized	Functionalization Production	Transmission	Distribution/ Other
	(1)	(2)	(3)	(4)	(5)
	Production:				
1	Fuel 501,518,547	13,377	13,377	0	0
2	Purchased Power 555	23,927	23,927	0	0
	Operations & Maintenance				
3	Steam 500, 502-514	5,321	5,321	0	0
4	Nuclear 517,519-532	0	0	0	0
5	Hydro 535-545	2,595	2,595	0	0
6	Other 546,548-554,556-557	363	363	0	0
7	Total Production Expense	45,583	45,583	0	0
8	Transmission 560-573 a/	6,434	0	6,434	0
9	Distribution 580-598 b/	4,796	0	0	4,796
10	Customer Accounting 901-905 i/	4,457	0	0	4,457
11	Customer Assistance 907-910 i/	2,127	0	0	2,127
12	Sales Expense 911-916	98	0	0	98
	Administrative & General i/				
13	920 Admin & General Salaries	2,657	395	114	2,148
14	921 Office Supplies & Expenses	758	113	32	613
15	922 Admin Expenses transferred - Cr.	(228)	(34)	(10)	(184)
16	923 Outside Services Employed	541	80	23	437
17	924 Property Insurance	121	60	20	41
18	925 Injuries & Damages	745	111	32	602
19	926 Employee Pensions & Benefits	3,833	570	164	3,099
20	927 Franchise Requirements	540	0	0	540
21	928 Regulatory Commission Expenses	1,079	0	0	1,079
22	929 Duplicate Charges - Cr.	0	0	0	0
23	930.1 General Advertising Expenses	1,066	0	0	1,066
24	930.2 Miscellaneous General Expenses	0	0	0	0
25	931 Rents	407	0	0	407
26	932 Maintance of General Plant	689	297	96	296
27					
28	Total A & G	12,208	1,592	472	10,145
29					
30	Total Operations & Maintenance	75,703	47,175	6,906	21,623

Washington Water Power Company
RESIDENTIAL PURCHASE AND SALE AGREEMENT
Jurisdiction: Washington
Average System Cost Methodology
Test Period: 1-1-83/12-1-83
Filing # 9-A2-8501
Taxes Other Than Income Taxes
(Thousands)

Line No.	Items	Functionalization: Total To Be Functionalized	Production	Transmission	Distribution/ Other
	(1)	(2)	(3)	(4)	(5)
1	FEDERAL - Insurance Contributions	1,130	168	48	914
2	- Unemployment	33	5	1	27
3	- Income Tax	12,413	0	0	12,413
4	In-Lieu Tax	0	0	0	0
5	Other Tax	0	0	0	0
6	State Of: Washington				
7	-State Income Taxes	0	0	0	0
8	-State Property Tax	5,076	2,504	832	1,740
	-State Unemp. Tax	206	31	9	167
10	-State Reg. Commis. Tax	0	0	0	0
11	-State Generating Tax	433	0	0	433
12	-State Pollution Control Tax	0	0	0	0
13	-State Rev. & Business Tax	0	0	0	0
14	-Local Occupation & Franchise	0	0	0	0
15	-Excise	7,791	0	0	0
16	-Misc.	8	0	0	0
17	-	0	0	0	0
18	State Of: Montana				
19	-State Income Taxes	(31)	0	0	(31)
20	-State Property Tax	0	0	0	0
21	-State Unemp. Tax	0	0	0	0
22	-State Reg. Commis. Tax	0	0	0	0
23	-State Generating Tax	0	0	0	0
24	-State Pollution Control Tax	0	0	0	0
25	-State Rev. & Business Tax	0	0	0	0
26	-Local Occupation & Franchise	0	0	0	0
27	-	0	0	0	0
28	-	0	0	0	0
29	-	0	0	0	0
30	TOTAL	27,059	2,708	891	15,662

Washington Water Power Company
RESIDENTIAL PURCHASE AND SALE AGREEMENT
Jurisdiction: Washington
Average System Cost Methodology
Test Period: 1-1-83/12-1-83
Filing # 9-A2-B501
Average System Cost
(Thousands)

Line No.	ITEMS	AMOUNTS
	(1)	(2)
	Contract System Cost:	
1	Production Cost (From Schedule 3)	63,274
2	Transmission Cost (From Schedule 3)	14,853
3	Less: Excluded Load Costs	(0)
4	Total Contract System Costs	78,127
	Contract System Load:	
5	Total Load (MWh)	3,816,842
	Less:	
6	Nonfirm Adjusment (MWh)	(0)
7	Other Adjustments (MWh)	(0)
8	Net Load (MWh)	3,816,842
	Plus:	
9	Distribution Losses (MWh) g/	345,843
10	Total Net Load (MWh)	4,162,685
	Less:	
11	Excluded Load (MWh) f/	(0)
12	Excluded Load Distribution Losses (MWh)	(0)
13	Total Contract System Load (MWh)	4,162,685
14	Average System Cost (mills/kWh) (Line 4 / Line 13)	18.77

Washington Water Power Company
Jurisdiction Washington
RESIDENTIAL PURCHASE AND SALE AGREEMENT
Average System Cost Methodology
Test Period 1-1-83/12-1-83
Filing # 9-A2-8501
Calculation of Ratios
(Thousands)

Line No.	RATIOS		Total To Be Functionalized	Production	Transmission	Distribution
(GP)	RATIO OF GENERAL PLANT ACCOUNTS	Ratio Used				
1.	A/C 389 Land & Land Rights	PTD/10%	492	246	80	165
2.	A/C 390 Structures & Improvements	PTD/10%	10,600	5,308	1,727	3,565
3.	A/C 391 Office Furniture	LABOR/10%	3,113	463	133	2,517
4.	A/C 392 Transportation Equipment	TD/10%	3,296	0	1,076	2,220
5.	A/C 393 Stores Equipment	PTD	116	58	19	39
6.	A/C 394 Tools, Shop & Garage Equipment	PTD	681	341	111	229
7.	A/C 395 Labratory Equipment	PTD	291	146	47	98
8.	A/C 396 Power Operated Equipment	TD	2,314	0	755	1,559
9.	A/C 397 Communications Equipment	PTD	2,547	1,275	415	857
10.	A/C 398 Miscellaneous Equipment	DIST	77	0	0	77
11.	A/C 399 Other Tangible Property	PTD	0	0	0	0
12.	TOTAL		23,527	7,838	4,364	11,326
13.	RATIO (GP)		100.00%	33.31%	18.55%	48.14%
(PTD)	RATIO OF PRODUCTION, TRANSMISSION, DISTRIBUTION PLANT					
	PRODUCTION PLANT					
14.	Steam Production 310-316		144,688	144,688	0	0
15.	Nuclear Production 320-325		0	0	0	0
16.	Hydraulic Production 330-336		101,008	101,008	0	0
17.	Other Production Plant 340-346		7,885	7,885	0	0
18.	Total Production Plant		253,581	253,581	0	0
19.	Transmission Plant 350-359		82,508	0	82,508	0
20.	Distribution Plant 360-373		170,298	0	0	170,298
21.						
22.	TOTAL		506,387	253,581	82,508	170,298
23.	RATIO (PTD = PLANT IN SERVICE)		100.00%	50.08%	16.29%	33.63%

Line No.	RATIOS		Total To Be Functionalized	Production	Transmission	Distribution
(LABOR)	RATIO OF LABOR					
43.	Production 500-557	(Labor only)	2,019	2,019	0	0
44.	Transmission 560-573	(")	582	0	582	0
45.	Distribution 580-598	(")	3,488	0	0	3,488
46.	Customer Account 901-905	(")	0	0	0	0
47.	Customer Service 907-910	(")	4,080	0	0	4,080
48.	Sales Expense 911-916	(")	0	0	0	0
49.	Admin. & General 920-932	(")	3,412	0	0	3,412
50.	TOTAL		13,581	2,019	582	10,980
51.	RATIO (LABOR)		100.00%	14.87%	4.29%	80.85%

************* DATA MATRIX **************

...NT NUMBER	ACCOUNT DESCRIPTION	Funct. Method	Total TBF	Funct-Prod	Funct-Trans	Funct-Dist	Math Check
SCHEDULE 1 ITEMS							
310-316	Steam Prod. Plant	DIR-P	144,688	144,688			0
320-325	Nuclear Prod. Plant	DIR-P		0			0
330-336	Hydraulic Prod. Plant	DIR-P	101,008	101,008			0
340-346	Other Prod Plant	DIR-P	7,885	7,885			0
350-359	Transmission Plant	DIR-T	82,508		82,508		0
360-373	Distribution Plant	DIR-D	170,298			170,298	0
301-303	Intangible Plant	DIRECT	116	116			0
389	Land and Land Rights	PTD	492	246	80	165	(0)
389-10%	Land and Land Rights	10%TD		0	0	0	0
390	Structures and improv	PTD	10,600	5,308	1,727	3,565	(0)
390-10%	Structures and improv	10%TD		0	0	0	0
391	Office Furniture and Equip	LABOR	3,113	463	133	2,517	0
391-10%	Office Furniture and Equip	10%TD		0	0	0	0
392	Transportation Equipment	TD	3,296	0	1,076	2,220	0
392-10%	Transportation Equipment	10%TD		0	0	0	0
393	Stores Equipment	PTD	116	58	19	39	(0)
394	Tools, Shop and Garage Eq	PTD	681	341	111	229	(0)
395	Laboratory Equipment	PTD	291	146	47	98	(0)
396	Power Operated Equipment	TD	2,314	0	755	1,559	0
397	Communication Equipment	PTD	2,547	1,275	415	857	0
398	Miscellaneous Equipment	DIR-D	77			77	0
399	Other Tangible Property	PTD		0	0	0	0
108	Steam - Depr. Reserve	(3C) DIR-P	10,380	10,380			0
108	Nuclear - Depr. Reserve	(3C) DIR-P		0			0
108	Hydro - Depr. Reserve	(3C) DIR-P	12,735	12,735			0
108	Other - Depr. Reserve	(3C) DIR-P	1,663	1,663			0
108	Trans. - Depr. Reserve	(3C) DIR-T	15,312		15,312		0
108	Distr. - Depr. Reserve	(3C) DIR-D	42,561			42,561	0
108	General - Depr. Reserve	(3C) GP	6,008	2,001	1,114	2,892	0
111	Amortization Reserve	(3C)AS 301-3	61	61			0
	Cash Working Capital-See CWC						0
105	Plant Held Future Use	PTDG		0	0	0	0
106	Completed Construction	PTD		0	0	0	0
107,120.1	CWIP	(3C) DIR-D				0	0
114	Acquisitions Adjustments	LABOR		0	0	0	0
120.2-120.4	Nuclear Fuel	DIR-P		0			0
123	Investments	DIR-D				0	0
124	Other Investments	DIR-D				0	0
	Weatherization Investment	DIR-P	12,552	12,552			0
151-152	Fuel Stock	DIR-P		0			0
153-157,163	Mat. & Sup.	TDG		0	0	0	0
184	Clearing Accounts	LABOR		0	0	0	0
186	Misc. Defered Debits	LABOR		0	0	0	0
252	Customer Advances, Const.	DIR-D				0	0
253	Other deferred credits	DIR-D				0	0
255	Accumulated def inv tax cr	DIR-D	5,206			5,206	0
256	Deferred Gain -Disposition	(3C) PTDG+		0	0	0	0
257	Unamortized Gain - Reacq.	PTDG		0	0	0	0
281-283	Accum def income taxes	DIR-D	6,131			6,131	0

************* DATA MATRIX **************

SCHEDULE 3A ITEMS

~UNT NUMBER	ACCOUNT DESCRIPTION	Funct. Method	Total TBF	Funct-Prod	Funct-Trans	Funct-Dist	Math Check
	Fed Tax-Insurance Contribu	(3C) LABOR	1,130	168	48	914	(0)
	Fed Tax-Unemployment	(3C) LABOR	33	5	1	27	0
	In-lieu Tax	DIR-D				0	0
	Other Taxes	(3C) DIR-D				0	0
	Federal Income Taxes	(3C) DIR-D	12,413			12,413	0

Note: Enter the state in cell block V156 of schedule 3A

State of: Washington

	State Income Taxes	(3C) DIR-D				0	0
	State Property Tax	(3C) PTDG	5,076	2,504	832	1,740	0
	State Unemp. Tax	(3C) LABOR	206	31	9	167	(0)
	State Reg. Commis. Tax	(3C) DIR-D				0	0
	State Generating Tax	(3C) DIR-D	433			433	0
	State Pollution Control Ta	(3C) DIR-D				0	0
	State Rev. & Business Tax	(3C) DIR-D				0	0
	Local Occupation & Franchi	(3C) DIR-D				0	0
	-Excise	(3C) DIR-D	7,791				
~ional	-Misc.	(3C) DIR-D	8				
Tax Items	-						

Note: Enter the state in cell block V169 of schedule 3A

State of: Montana

	State Income Taxes	(3C) DIR-D	(31)			(31)	0
	State Property Tax	(3C) PTDG		0	0	0	0
	State Unemp. Tax	(3C) LABOR		0	0	0	0
	State Reg. Commis. Tax	(3C) DIR-D				0	0
	State Generating Tax	(3C) DIR-D				0	0
	State Pollution Control Ta	(3C) DIR-D				0	0
	State Rev. & Business Tax	(3C) DIR-D				0	0
	Local Occupation & Franchi	(3C) DIR-D				0	0
Add	-						
Additional	-						
Tax Items	-						

SCHEDULE 3B ITEMS

411.6	Gain from Disp. of Plant	(3C) PTDG*		0	0	0	
411.7	Loss from Disp. of Plant	(3C) PTDG*		0	0	0	0
447	-Nonfirm Sales For Resale	DIR-P	16,641	16,641			0
	-	DIR-P		0			0
450	Forfeited discounts	DIR-F		0			0
451	Miscellaneous Service Reve	DIR-P	72	72			0
453	Sales of water/water power	DIR-P	235	235			0
454	Rent from property	DIR-P	483	483			0
455	Interdepartmental rents	DIR-P		0			0
456	[illegible]	[illegible]	[illegible]	[illegible]			0
	Billing Credits	DIR-P		0			0

1983

Form Approved
OMB No. 1902-0021
(Expires 12/31/84)

182 + 183
balance sheet
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FERC FORN
ANNUAL REPORT
UTILITIES, LICENSEI
(Class A and

This report is mandatory under the Federal Power Act, Sections 3,4(a), 304 and 309, and 18 CFR 141.1. Failure to report may result in criminal fines, civil penalties and other sanctions as provided by law. The Federal Energy Regulatory Commission does not consider this report to be of a confidential nature.

138-92-30
8
11/5:147

Exact Legal Name of Respondent (Company)	Year of Report
THE WASHINGTON WATER POWER COMPANY	Dec. 31, 19 83

FERC FORM NO. 1 (REVISED 12-82)

INSTRUCTIONS FOR FILING THE FERC FORM NO. 1

GENERAL INFORMATION

I. Purpose

This form is a regulatory support requirement (18 CFR 141.1). It is designed to collect financial and operational information from public utilities, licensees and others subject to the jurisdiction of the Federal Energy Regulatory Commission. This report is also secondarily considered to be a non-confidential public use form supporting a statistical publication (Statistics of Privately Owned Electric Utilities in the United States) published by the Energy Information Administration.

II. Who Must Submit

Each Class A and Class B public utility, licensee, or other, as classified in the Commission's Uniform System of Accounts Prescribed for Public Utilities and Licensees Subject To the Provisions of The Federal Power Act (18 CFR 101) must submit this form.

Note: Class A means having annual electric operating revenues of $2,500,000 or more.
Class B means having annual electric operating revenues of more than $1,000,000 but less than $2,500,000.

III. What and Where to Submit

(a) Submit an original and six (6) copies of this form to:

U.S. Department of Energy
Energy Information Administration EI-541
Mail Station BI-094
Forrestal Building
Washington, D.C. 20585

Retain one copy of this report for your files.

(b) Submit immediately upon publication, four (4) copies of the latest annual report to stockholders and any *annual* financial or statistical report regularly prepared and distributed to bondholders, security analyst, or industry association. (Do not include monthly and quarterly reports. If reports to stockholders are not prepared, enter "NA" in column (d) on Page 4, the List of Schedules.) Mail these reports to:

Chief Accountant
Federal Energy Regulatory Commission
825 N. Capitol St., N.E.
Room 601-RB
Washington, D.C. 20426

(c) For the CPA certification, submit with the original submission, or within 30 days after the filing date for this form, a letter or report:

(i) Attesting to the conformity, in all material aspects, of the below listed (schedules and) pages with the Commission's applicable Uniform Systems of Accounts (including applicable notes relating thereto and the Chief Accountant's published accounting releases), and

(ii) Signed by independent certified public accountants or an independent licensed public accountant, certified or licensed by a regulatory authority of a State or other political subdivision of the U.S. (See 18 CFR 41.10-41.12 for specific qualifications.)

Schedules	Reference Pages
Comparative Balance Sheet	110-113
Statement of Income	114-117
Statement of Retained Earnings	118-119
Statement of Changes in Financial Position	120-121
Notes to Financial Statements	122-123

When accompanying this form, insert the letter or report immediately following the cover sheet.

GENERAL INFORMATION (Continued)

III. What and Where to Submit (Continued)

(c) (Continued)

Use the following form for the letter or report unless unusual circumstances or conditions, explained in the letter or report, demand that it be varied. Insert parenthetical phrases only when exceptions are reported.

In connection with our regular examination of the financial statement of for the year ended on which we have reported separately under date of we have also reviewed schedules of form 1 for the year filed with the Federal Energy Regulatory Commission, for conformity in all material respects with the requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases. Our review for this purpose included such tests of the accounting records and such other auditing procedures as we considered necessary in the circumstances.

Based on our review, in our opinion the accompanying schedules identified in the preceding paragraph (except as noted below) conform in all material respects with the accounting requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases.

State in the letter or report which, if any, of the pages above do not conform to the Commission's requirements. Describe the discrepancies that exist.

(d) Federal, State and Local Governments and other authorized users may obtain additional blank copies to meet their requirements free of charge from:

U.S. Department of Energy
National Energy Information Center
Energy Information Administration
Washington, D.C. 20585
(202) 252-8800

IV. When to Submit:

Submit this report form on or before April 30th of the year following the year covered by this report.

GENERAL INSTRUCTIONS

I. Prepare this report in conformity with the Uniform System of Accounts (18CFR 101) (U.S. of A.). Interpret all accounting words and phrases in accordance with the U.S. of A.

II. Enter in whole numbers (dollars or MWH) only, except where otherwise noted. (Enter cents for averages and figures per unit where cents are important. The truncating of cents is allowed except on the four basic financial statements where rounding is required.) The amounts shown on all supporting pages must agree with the amounts entered on the statements that they support. When applying thresholds to determine significance for reporting purposes, use for balance sheet accounts the balances at the end of the current reporting year, and use for statement of income accounts the current years amounts.

III. Complete each question fully and accurately, even if it has been answered in a previous annual report. Enter the word "None" where it truly and completely states the fact.

IV. For any page(s) that is not applicable to the respondent, either

(a) Enter the words "Not Applicable" on the particular page(s), or

(b) Omit the page(s) and enter "NA", "None", or "Not Applicable" in column (d) on the List of Schedules, pages 2, 3, and 4.

V. Complete this report by means which result in a permanent record. Complete the original copy in permanent black ink or typewriter print, if practical. The copies, however, may be carbon copies or other similar means of reproduction provided the impressions are clear and readable.

GENERAL INSTRUCTIONS (Continued)

VI. Enter the month, day, and year for all dates. Use customary abbreviations. The "Date of Report" at the top of each page is applicable only to resubmissions (see VIII. below).

VII. Indicate negative amounts (such as decreases) by enclosing the figures in parentheses ( ).

VIII. When making revisions, resubmit only those pages that have been changed from the original submission. Submit the same number of copies as required for filing the form. Include with the resubmission the Identification and Attestation page, page 1. Mail dated resubmissions to:

Chief Accountant
Federal Energy Regulatory Commission
825 North Capitol Street, N.E.
Room 601-RB
Washington, D.C. 20426

IX. Provide a supplemental statement further explaining accounts or pages as necessary. Attach the supplemental statement (8½ by 11 inch size) to the page being supplemented. Provide the appropriate identification information, including the title(s) of the page and the page number supplemented.

X. Do not make references to reports of previous years or to other reports in lieu of required entries, except as specifically authorized.

XI. Wherever (schedule) pages refer to figures from a previous year, the figures reported must be based upon those shown by the annual report of the previous year, or an appropriate explanation given as to why the different figures were used.

XII. Respondents may submit computer printed schedules (reduced to 8½ by 11) instead of the preprinted schedules if they are in substantially the same format.

DEFINITIONS

I. <u>Commission Authorization (Comm. Auth.)</u> — The authorization of the Federal Energy Regulatory Commission, or any other Commission. Name the commission whose authorization was obtained and give date of the authorization.

II. <u>Respondent</u> — The person, corporation, licensee, agency, authority, or other legal entity or instrumentality in whose behalf the report is made.

EXCERPTS FROM THE LAW

(Federal Power Act, 18 U.S.C. 791a-825r)

"Sec. 3. The words defined in this section shall have the following meanings for purposes of this Act, to wit:

...(3) 'corporation' means any corporation, joint-stock company, partnership, association, business trust, organized group of persons, whether incorporated or not, or a receiver or receivers, trustee or trustees of any of the foregoing. It shall not include 'municipalities' as hereinafter defined;

(4) 'person' means an individual or a corporation;

(5) 'licensee' means any person, State, or municipality licensed under the provisions of section 4 of this Act, and any assignee or successor in interest thereof;

(7) 'municipality' means a city, county, irrigation district, drainage district, or other political subdivision or agency of a State competent under the laws thereof to carry on the business of developing, transmitting, utilizing, or distributing power;...."

(11) 'project' means a complete unit of improvement or development, consisting of a power house, all water conduits, all dams and appurtenant works and structures (including navigation structures) which are a part of said unit, and all storage, diverting, a forebay reservoirs directly connected therewith, the primary line or lines transmitting power therefrom to the point of junction with the distribution system or with the interconnected primary transmission system, all miscellaneous structures used and useful in connection with said unit as any part thereof, and all water rights, rights-of-way, ditches, dams, reservoirs, lands, or interest in lands the use and occupancy of which are necessary or appropriate in the maintenance and operation of such unit;

EXCERPTS FROM THE LAW (Continued)

"Sec. 4. The Commission is hereby authorized and empowered—

(a) To make investigations and to collect and record data concerning the utilization of the water resources of any region to be developed, the water-power industry and its relation to other industries and to interstate or foreign commerce, and concerning the location, capacity, development costs, and relation to markets of power sites,...to the extent the Commission may deem necessary or useful for the purposes of this Act."

"Sec. 304. (a) Every licensee and every public utility shall file with the Commission such annual and other periodic or special reports as the Commission may by rules and regulations or order prescribe as necessary or appropriate to assist the Commission in the proper administration of this Act. The Commission may prescribe the manner and form in which such reports shall be made, and require from such persons specific answers to all questions upon which the Commission may need information. The Commission may require that such reports shall include, among other things, full information as to assets and liabilities, capitalization, net investment, and reduction thereof, gross receipts, interest due and paid, depreciation, and other reserves, cost of project and other facilities, cost of maintenance and operation of the project and other facilities, cost of renewals and replacement of the project works and other facilities, depreciation, generation, transmission, distribution, delivery, use, and sale of electric energy. The Commission may require any such person to make adequate provision for currently determining such costs and other facts. Such reports shall be made under oath unless the Commission otherwise specifies."

"Sec. 309. The Commission shall have power to perform any and all acts, and to prescribe, issue, make, amend, and rescind such orders, rules and regulations as it may find necessary or appropriate to carry out the provisions of this Act. Among other things, such rules and regulations may define accounting, technical, and trade terms used in this Act; and may prescribe the form or forms of all statements, declarations, applications, and reports to be filed with the Commission, the information which they shall contain, and the time within which they shall be filed...."

GENERAL PENALTIES

"Sec. 315. (a) Any licensee or public utility which willfully fails, within the time prescribed by the Commission, to comply with any order of the Commission, to file any report required under this Act or any rule or regulation of the Commission thereunder, to submit any information or document required by the Commission in the course of an investigation conducted under this Act,...shall forfeit to the United States an amount not exceeding $1,000 to be fixed by the Commission after notice and opportunity for hearing...."

FERC FORM NO 1:
ANNUAL REPORT OF ELECTRIC UTILITIES, LICENSEES AND OTHERS (Class A and Class B)

IDENTIFICATION

01 Exact Legal Name of Respondent The Washington Water Power Company	02 Year of Report Dec. 31, 19 83
03 Previous Name and Date of Change *(If name changed during year)*	
04 Address of Principal Business Office at End of Year *(Street, City State, Zip Code)* P.O. Box 3727, Spokane, Washington 99220	
05 Name of Contact Person H. E. Odean	06 Title of Contact Person Vice President - Finance
07 Address of Contact Person *(Street, City, State, Zip Code)* P.O. Box 3727, Spokane, Washington 99220	

08 Telephone of Contact Person, *Including Area Code*	09 This Report Is	10 Date of Report *(Mo, Da, Yr)*
(509) 489-0500, Ext. 2345	(1) ☒ An Original (2) ☐ A Resubmission	April 30, 1984

ATTESTATION

The undersigned officer certifies that he/she has examined the accompanying report; that to the best of his/her knowledge, information, and belief, all statements of fact contained in the accompanying report are true and the accompanying report is a correct statement of the business and affairs of the above named respondent in respect to each and every matter set forth therein during the period from and including January 1 to and including December 31 of the year of the report.

01 Name	03 Signature	04 Date Signed *(Mo, Da, Yr)*
W. J. Satre	W. J. Satre	April 9, 1984
02 Title Chairman of the Board and Chief Executive Officer		

Title 18, U.S.C. 1001, makes it a crime for any person knowingly and willingly to make to any Agency or Department of the United States any false, fictitious or fraudulent statements as to any matter within its jurisdiction.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
The Washington Water Power Company	(1) ☒ An Original (2) ☐ A Resubmission	April 30, 1984	Dec. 31, 19 83

LIST OF SCHEDULES (Electric Utility)

Enter in column (d) the terms "none," "not applicable," or "NA" as appropriate, where no information or amounts have been reported for certain pages. Omit pages where the responses are "none," "not applicable," or "NA."

Title of Schedule (a)	Reference Page No. (b)	Date Revised (c)	Remarks (d)
GENERAL CORPORATE INFORMATION AND FINANCIAL STATEMENTS			
General Information	101		
Control Over Respondent	102		None
Corporations Controlled by Respondent	103		
Officers	104		
Directors	105		
Security Holders and Voting Powers	106–107		
Important Changes During the Year	108–109		
Comparative Balance Sheet	110–113		
Statement of Income for the Year	114–117		
Statement of Retained Earnings for the Year	118–119		
Statement of Changes in Financial Position	120–121		
Notes to Financial Statements	122–123		
BALANCE SHEET SUPPORTING SCHEDULES (Assets and Other Debts)			
Summary of Utility Plant and Accumulated Provisions for Depreciation, Amortization, and Depletion	200		
Nuclear Fuel Materials	201		
Electric Plant in Service	202–204		
Electric Plant Leased to Others	207		None
Electric Plant Held for Future Use	208		None
Construction Work in Progress – Electric	210		
Construction Overheads – Electric	211		
General Description of Construction Overhead Procedure	212		
Accumulated Provision for Depreciation of Electric Utility Plant	213		
Nonutility Property	215		
Investments in Subsidiary Companies	217		
Extraordinary Property Losses	220		None
Material and Supplies	218		
Miscellaneous Deferred Debits	223		
Accumulated Deferred Income Taxes (Account 190)	224		None
BALANCE SHEET SUPPORTING SCHEDULES (Liabilities and Other Credits)			
Capital Stock	250		
Capital Stock Subscribed, Capital Stock Liability for Conversion, Premium on Capital Stock, and Installments Received on Capital Stock	251		
Other Paid-In Capital	252		None
Discount on Capital Stock	253		
Capital Stock Expense	253		
Long-Term Debt	256-257		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
The Washington Water Power Company	(1) [X] An Original (2) [ ] A Resubmission	April 30, 1984	Dec. 31, 19 83

LIST OF SCHEDULES (Electric Utility) (Continued)

Attachment 5-4
Forecasts and Backcasts of Average System Costs and Loads for FY 2002 Through 2008
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
The Washington Water Power Company	(1) [X] An Original (2) [ ] A Resubmission	April 30, 1984	Dec. 31, 19 83

LIST OF SCHEDULES (Electric Utility) (Continued)

Title of Schedule (a)	Reference Page No. (b)	Date Revised (c)	Remarks (d)
ELECTRIC PLANT STATISTICAL DATA (Continued)			
Pumped Storage Generating Plants	416–418		None
Internal-Combustion Engine and Gas-Turbine Generating Plants	420–421		
Transmission Line Statistics	422–423		
Transmission Lines Added During Year	424		
Substations	425		
Electric Distribution Meters and Line Transformers	427		
Environmental Protection Facilities	428		
Environmental Protection Expenses	429		
Footnote Data	450		
Stockholders' Reports	–		None

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
The Washington Water Power Company	(1) [X] An Original (2) [ ] A Resubmission	April 30, 1984	Dec. 31, 19 83

GENERAL INFORMATION

1. Provide name and title of officer having custody of the general corporate books of account and address of office where the general corporate books are kept, and address of office where any other corporate books of account are kept, if different from that where the general corporate books are kept.

H. E. Odean, Vice President - Finance
E. 1411 Mission Avenue
Spokane, Washington 99202

2. Provide the name of the State under the laws of which respondent is incorporated, and date of incorporation. If incorporated under a special law, give reference to such law. If not incorporated, state that fact and give the type of organization and the date organized.

Incorporated March 15, 1889 in the State of Washington.

3. If at any time during the year the property of respondent was held by a receiver or trustee, give (a) name of receiver or trustee, (b) date such receiver or trustee took possession, (c) the authority by which the receivership or trusteeship was created, and (d) date when possession by receiver or trustee ceased.

Not Applicable

4. State the classes of utility and other services furnished by respondent during the year in each State in which the respondent operated.

Electric service in the States of Washington, Idaho and Montana.

Gas service in the States of Washington and Idaho.

Steam heat service in the State of Washington.

Water service in the State of Washington.

5. Have you engaged as the principal accountant to audit your financial statements an accountant who is not the principal accountant for your previous year's certified financial statements?

(1) [ ] YES ...Enter the date when such independent accountant was initially engaged:__________.
(2) [X] NO

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
The Washington Water Power Company	(1) [X] An Original (2) [ ] A Resubmission	April 30, 1984	Dec. 31, 19 83

CORPORATIONS CONTROLLED BY RESPONDENT

1. Report below the names of all corporations, business trusts, and similar organizations, controlled directly or indirectly by respondent at any time during the year. If control ceased prior to end of year, give particulars (details) in a footnote.
2. If control was by other means than a direct holding of voting rights, state in a footnote the manner in which control was held, naming any intermediaries involved.
3. If control was held jointly with one or more other interests, state the fact in a footnote and name the other interests.
4. If the above required information is available from the SEC 10-K Report Form filing, a specific reference to the report form (i.e. year and company title) may be listed in column (a) provided the fiscal years for both the 10-K report and this report are compatible.

DEFINITIONS

1. See the Uniform System of Accounts for a definition of control.
2. Direct control is that which is exercised without interposition of an intermediary.
3. Indirect control is that which is exercised by the interposition of an intermediary which exercises direct control.
4. Joint control is that in which neither interest can effectively control or direct action without the consent of the other, as where the voting control is equally divided between two holders, or each party holds a veto power over the other. Joint control may exist by mutual agreement or understanding between two or more parties who together have control within the meaning of the definition of control in the Uniform System of Accounts, regardless of the relative voting rights of each party.

Name of Company Controlled (a)	Kind of Business (b)	Percent Voting Stock Owned (c)	Footnote Ref. (d)
Direct Control			
Washington Irrigation & Development Company	Operating company mining coal for a steam generating plant near Centralia, WA.	100%	
Spokane Industrial Park, Inc.	Operating company organized for the purpose of owning and leasing property to manufacturing and other business enterprises.	99%	
Water Power Improvement Company	Owns 64% of ITRON, Inc. which is engaged in research, development and leasing of a portable billing system.	100%	
Development Associates, Inc.	Operating company organized for the investigation and drilling for gas and oil deposits and for sales of gas.	100%	
WP Energy Co.	Operating company organized to finance and construct a wood-waste-fired generation facility.	100%	(1)
The Limestone Company, Inc.	Nonoperating company which owns certain lands located in Nez Perce County and Kootenai County, Idaho.	92%	
Empire Energy Company	Nonoperating company	100%	

Name of Company Controlled (a)	Kind of Business (b)	Percent Voting Stock Owned (c)	Footnote Ref. (d)
Spokane Suburban Water Supply, Inc.	Nonoperating company organized to sell the Company's Spokane Water System.	100%	(4)
Clarkston General Water Supply, Inc.	Nonoperating company organized to sell the Company's Clarkston Water System.	100%	(4)
Joint Control			
Pacific Northwest Power Company	Nonoperating company organized to investigate, develop, and eventually operate hydroelectric projects in the Pacific Northwest.	25%	(2)
Northwest Energy Services Company	Operating company organized to plan, construct, operate and maintain generating facilities in the Northwest.	25%	(3)

Notes: (1) WP Energy Co. was merged into the Respondent on August 3, 1983.

(2) Jointly controlled by Respondent, Pacific Power & Light Company, The Montana Power Company, and Portland General Electric Company.

(3) Jointly controlled by Respondent, Pacific Power & Light Company, Puget Sound Power & Light Co., and Portland General Electric Company.

(4) Sold to General Waterworks Corp. February 28, 1983.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
The Washington Water Power Company	(1) [x] An Original (2) [ ] A Resubmission	April 30, 1984	Dec. 31, 19 83

OFFICERS

1. Report below the name, title and salary for each executive officer whose salary is $50,000 or more. An "executive officer" of a respondent includes its president, secretary, treasurer, and vice president in charge of a principal business unit, division or function (such as sales, administration or finance), and any other person who performs similar policymaking functions.

2. If a change was made during the year in the incumbent of any position, show name and total remuneration of the previous incumbent, and date the change in incumbency was made.

3. Utilities which are required to file the same data with the Securities and Exchange Commission, may substitute a copy of item 4 of Regulation S-K (identified as this page). The substituted page(s) should be the same size as this page.

Line No.	Title (a)	Name of Officer (b)	Salary for Year (c)
1	Chairman of the Board & Chief Executive		
2	Officer	W. J. Satre	173,300
3	President & Chief Operating Officer	Paul A. Redmond	136,475
4	Sr. Vice President - Resources	D. L. Olson	94,177
5	Vice President - Operations	J. R. Harvey	77,900
6	Vice President - Finance	H. E. Odean	71,300
7	Vice President and Secretary	J. P. Buckley	63,396
8	Vice President - Power Supply (1)	H. W. Harding	48,611
9	Vice President - Power Supply (2)	W. L. Bryan	59,512
10	Vice President - Gas Supply	R. T. McLendon	63,500
11	Vice President - Employee Relations &		
12	Administrative Services	O. I. Quarta	67,100
13	Vice President - Public Relations &		
14	Public Affairs	J. R. Piedmont	65,700
15	Treasurer	J. E. Eliassen	53,036
16	Controller	H. R. Reinhardt	54,037
17			
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21			
22	Note: (1) Retired July 31, 1983.		
23			
24	(2) Effective Vice President - Power Supply August 1, 1983.		
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Attachment 5-4
Forecasts and Backcasts of Average System Costs and Loads for FY 2002 Through 2008
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
The Washington Water Power Company	(1) [X] An Original (2) [ ] A Resubmission	April 30, 1984	Dec. 31, 19 83

DIRECTORS

1. Report below the information called for concerning each director of the respondent who held office at any time during the year. Include in column (a) abbreviated titles of the directors who are officers of the respondent.

2. Designate members of the Executive Committee by an asterisk and the Chairman of the Executive Committee by a double asterisk.

Name (and Title) of Director (a)	Principal Business Address (b)
W. J. Satre** Chairman of the Board & Chief Executive Officer	E. 1411 Mission Avenue, Spokane, WA 99202
Paul A. Redmond* President & Chief Operating Officer	E. 1411 Mission Avenue, Spokane, WA 99202
Rodney G. Aller	P.O. Box 406, Lakeville, CT 06039
Duane B. Hagadone*	Hagadone Bldg., Coeur d'Alene, ID 83814
Edward W. Kiemle*	315 Washington Mutual Bldg., Spokane, WA 99201
James B. McMonigle*	P.O. Box 613, Lewiston, ID 83501
James A. Poore, Jr.	1341 Harrison Avenue, Butte, MT 59701
Margaret Charters Ross	W. 3202 Grandview Ave., Spokane, WA 99204
Eugene Thompson*	3307 Pine Crest Road, Moscow, ID 83843

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
The Washington Water Power Company	(1) [X] An Original (2) [ ] A Resubmission	April 30, 1984	Dec. 31, 1983

SECURITY HOLDERS AND VOTING POWERS

1. Give the names and addresses of the 10 security holders of the respondent who, at the date of the latest closing of the stock book or compilation of list of stockholders of the respondent, prior to the end of the year, had the highest voting powers in the respondent, and state the number of votes which each would have had the right to cast on that date if a meeting were then in order. If any such holder held in trust, give in a footnote the known particulars of the trust (whether voting trust, etc.), duration of trust, and principal holders of beneficiary interests in the trust. If the stock book was not closed or a list of stockholders was not compiled within one year prior to the end of the year, or if since the previous compilation of a list of stockholders, some other class of security has become vested with voting rights, then show such 10 security holders as of the close of the year. Arrange the names of the security holders in the order of voting power, commencing with the highest. Show in column (a) the titles of officers and directors included in such list of 10 security holders.

2. If any security other than stock carries voting rights, explain in a supplemental statement the circumstances whereby such security became vested with voting rights and give other important particulars (details) concerning the voting rights of such security. State whether voting rights are actual or contingent; if contingent, describe the contingency.

3. If any class or issue of security has any special privileges in the election of directors, trustees or managers, or in the determination of corporate action by any method, explain briefly in a footnote.

4. Furnish particulars (details) concerning any options, warrants, or rights outstanding at the end of the year for others to purchase securities of the respondent or any securities or other assets owned by the respondent, including prices, expiration dates, and other material information relating to exercise of the options, warrants, or rights. Specify the amount of such securities or assets so entitled to be purchased by any officer, director, associated company, or any of the ten largest security holders. This instruction is inapplicable to convertible securities or to any securities substantially all of which are outstanding in the hands of the general public where the options, warrants, or rights were issued on a prorata basis.

1. Give date of the latest closing of the stock book prior to end of year, and state the purpose of such closing:	2. State the total number of votes cast at the latest general meeting prior to the end of year for election of directors of the respondent and number of such votes cast by proxy	3. Give the date and place of such meeting:
November 22, 1983 to pay December 15, 1983 dividend.	Total: 15,120,976 By proxy: 15,120,976	May 13, 1983 Spokane, Washington

Line No.	Name (Title) and Address of Security Holder (a)	VOTING SECURITIES Number of votes as of (date): Total Votes (b)	Common Stock (c)	Preferred Stock (d)	Other (e)
4	TOTAL votes of all voting securities 20,130,830	20,130,830	20,130,830		
5	TOTAL number of security holders 50,201	49,156	49,156	1,045	
6	TOTAL votes of security holders listed below 7,685,337	7,685,337	7,685,337		
7	CEDE and Company, c/o Depository Trust Co., Box 863, Bowling Green Station,				
8	New York, NY 10274	5,095,505	5,095,505		
9	The Washington Water Power Company, Agent for WWP Dividend Reinvestment Account,				
10	P.O. Box 3727, Spokane, WA 99220	1,187,536	1,187,536		
11	Pacific & Company, Pacific Securities Depository, Box 7877, San Francisco,				
12	CA 94120	490,941	490,941		
13	Wabanc and Company (WWP TRASOP), c/o Washington Trust Bank, P.O. Box 2127,				
14	Spokane, WA 99210	458,196	458,196		
15	Kray & Company, P.O. Box 10645, Newark, NJ 07101	234,738	234,738		
16	Prudential-Bache Securities Inc., 100 Gold St., New York, NY 10038	58,355	58,355		
17	Wabanc & Company, c/o Trust Department, Washington Trust Bank, Box 2127,				
18	Spokane, WA 99210	50,279	50,279		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
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SECURITY HOLDERS AND VOTING POWERS (Continued)

Line No.	Name (Title) and Address of Security Holder (a)	Total Votes (b)	Common Stock (c)	Preferred Stock (d)	Other (e)
19	R. D. Ricketts, 3701 Kirby Bldg., Suite 705, Houston, TX 77098	39,500	39,500		
20	DAD & Company, P.O. Box 5015, Great Falls, MT 59403	38,287	38,287		
21	Otis E. Kline, 5226 North 69th Place, Scottsdale, AZ 85253 and The Hillman				
22	Company, c/o Amalgamated Bank of NY, 11-15 Union Square, New York, NY 10003	32,000	32,000		
23					
24					
25					
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28					
29	Note: Registered holders shown above may be nominees for beneficial owners. Respondent's records do not provide information concerning				
30	beneficial ownership of its Common Stock.				
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
The Washington Water Power Company	(1) [X] An Original (2) [ ] A Resubmission	April 30, 1984	Dec. 31, 19 83

IMPORTANT CHANGES DURING THE YEAR

Give particulars (details) concerning the matters indicated below. Make the statements explicit and precise, and number them in accordance with the inquiries. Each inquiry should be answered. Enter "none," "not applicable," or "NA" where applicable. If information which answers an inquiry is given elsewhere in the report, make a reference to the schedule in which it appears.

1. Changes in and important additions to franchise rights: Describe the actual consideration given therefor and state from whom the franchise rights were acquired. If acquired without the payment of consideration, state that fact.

2. Acquisition of ownership in other companies by reorganization, merger, or consolidation with other companies: Give names of companies involved, particulars concerning the transactions, name of the Commission authorizing the transaction, and reference to Commission authorization.

3. Purchase or sale of an operating unit or system: Give a brief description of the property, and of the transactions relating thereto, and reference to Commission authorization, if any was required. Give date journal entries called for by the Uniform System of Accounts were submitted to the Commission.

4. Important leaseholds (other than leaseholds for natural gas lands) that have been acquired or given, assigned or surrendered: Give effective dates, lengths of terms, names of parties, rents, and other conditions. State name of Commission authorizing lease and give reference to such authorization.

5. Important extension or reduction of transmission or distribution system: State territory added or relinquished and date operations began or ceased and give reference to Commission authorization, if any was required. State also the approximate number of customers added or lost and approximate annual revenues of each class of service. Each natural gas company must also state major new continuing sources of gas made available to it from purchases, development, purchase contract or otherwise, giving location and approximate total gas volumes available, period of contracts, and other parties to any such arrangements etc.

6. Obligations incurred as a result of issuance of securities or assumption of liabilities or guarantees including issuance of short-term debt and commercial paper having a maturity of one year or less. Give reference to FERC or State commission authorization, as appropriate, and the amount of obligation or guarantee.

7. Changes in articles of incorporation or amendments to charter: Explain the nature and purpose of such changes or amendments.

8. State the estimated annual effect and nature of any important wage scale changes during the year.

9. State briefly the status of any materially important legal proceedings pending at the end of the year, and the results of any such proceedings culminated during the year.

10. Describe briefly any materially important transactions of the respondent not disclosed elsewhere in this report in which an officer, director, security holder reported on page 106, voting trustee, associated company or known associate of any of these persons was a party or in which any such person had a material interest.

11. (Reserved.)

12. If the important changes during the year relating to the respondent company appearing in the annual report to stockholders are applicable in every respect and furnish the data required by instructions 1 to 11 above, such notes may be attached to this page.

1. None

2. Reference is made to Note 4 of Notes to Financial Statements, Page 122-G of this report.

3. On February 28, 1983, the Company sold its water properties. No commission approval was required.

4. None

5. None

6. Reference is made to Notes 2 thru 5 of Notes to Financial Statements, Pages 122-E through 122-G of this report.

7. None

8. Annualized increases for clerical, technical and exempt personnel in 1983 averaged 8.06%. Bargaining unit employees were granted a 4.05% increase.

9. On October 14, 1982, the Spokane Tribe of Indians filed a complaint in the United States District Court for the Eastern District of Washington against the Company and the State of Washington claiming ownership of the river bed of the Spokane River at the site of the Company's Little Falls Dam, a 36 Mw facility built in 1908. The complaint alleges that the title to the bed of the river at this site is held by the United States in trust for the Spokane Indian Tribe. The Spokane Tribe seeks a judgment awarding money damages in an unspecified amount to be proven at the time of trial. The Company has [illegible] judgment determining that at

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IMPORTANT CHANGES DURING THE YEAR (Continued)

the Company has, at least since 1910, had full right and authority to own and operate the dam. Reference is also made to Note 9 of Notes to Financial Statements, Pages 122-L through 122-R of this report.

Items 10 through 12 are either none or not applicable.

Name of Respondent	This Report Is	Date of Report (Mo, Da, Yr)	Year of Report
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COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Balance at Beginning of Year (c)	Balance at End of Year (d)
1	UTILITY PLANT			
2	Utility Plant (101-106, 114)	200	716,987,107	820,948,975
3	Construction Work in Progress (107)	200	391,708,495	392,954,161
4	TOTAL Utility Plant *(Enter Total of lines 2 and 3)*		1,108,695,602	1,213,903,136
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 111, 115)	200	160,282,890	167,239,642
6	Net Utility Plant, Less Nuclear Fuel *(Enter Total of line 4 less 5)*	–	948,412,712	1,046,663,494
7	Nuclear Fuel (120.1-120.4)	201		2,941,784
8	(Less) Accum. Prov. for Amort. of Nuclear Fuel Assemblies (120.5)	201		
9	Net Nuclear Fuel *(Enter Total of line 7 less 8)*	–		2,941,784
10	Net Utility Plant *(Enter Total of lines 6 and 9)*	–	948,412,712	1,049,605,278
11	Utility Plant Adjustments (116)	122		
12	Gas Stored Underground-Noncurrent (117)	–		
13	OTHER PROPERTY AND INVESTMENTS			
14	Nonutility Property (121)	215	998,837	1,383,627
15	(Less) Accum. Prov. for Depr. and Amort. (122)	–	50,832	36,364
16	Investments in Associated Companies (123)	–		
17	Investment in Subsidiary Companies (123.1)	217	33,453,499	35,826,213
18	*(For cost of Account 123.1, see footnote for line 23, page 217)*	–		
19	Other Investments (124)	–	15,189,589	16,725,531
20	Special Funds (125-128)	–		
21	TOTAL Other Property and Investments *(Enter Total of lines 14 thru 20)*	–	49,591,093	53,899,007
22	CURRENT AND ACCRUED ASSETS			
23	Cash (131)	–	1,247,607	186,080
24	Special Deposits (132-134)	–		
25	Working Funds (135)	–	260,024	254,791
26	Temporary Cash Investments (136)	–		
27	Notes Receivable (141)	–	23,005	62,054
28	Customer Accounts Receivable (142)	–	27,739,001	27,870,036
29	Other Accounts Receivable (143)	–	8,181,553	9,153,085
30	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)	–	802,249	1,567,970
31	Notes Receivable from Associated Companies (145)	–	1,187,215	
32	Accounts Receivable from Assoc. Companies (146)	–	109,783	32,272
33	Fuel Stock (151)	218	6,929,088	7,410,744
34	Fuel Stock Expense Undistributed (152)	218		
35	Residuals (Elec) and Extracted Products (Gas) (153)	218		
36	Plant Material and Operating Supplies (154)	218	6,351,995	6,635,014
37	Merchandise (155)	218		
38	Other Material and Supplies (156)	218		
39	Nuclear Materials Held for Sale (157)	201/218		
40	Stores Expenses Undistributed (163)	218	32,964	(9,447)
41	Gas Stored Underground – Current (164.1)	–		4,953,162
42	Liquefied Natural Gas Stored (164.2)	–	189,479	189,479
43	Liquefied Natural Gas Held for Processing (164.3)	–		
44	Prepayments (165)	–	266,005	363,915
45	Advances for Gas Explor., Devel. and Prod. (166)	–		
46	Other Advances for Gas (167)	–		
47	Interest and Dividends Receivable (171)	–	822,750	12,782
48	Rents Receivable (172)	–	7,681	101,152
49	Accrued Utility Revenues (173)	–		
50	Miscellaneous Current and Accrued Assets (174)	–	123,298	112,148
51	TOTAL Current and Accrued Assets *(Enter Total of lines 23 thru 50)*		52,669,199	55,759,297

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
The Washington Water Power Company	(1) [X] An Original (2) [ ] A Resubmission	April 30, 1984	Dec. 31, 19 83

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS) (Continued)

Line No.	Title of Account (a)	Ref. Page No. (b)	Balance at Beginning of Year (c)	Balance at End of Year (d)
52	DEFERRED DEBITS			
53	Unamortized Debt Expense (181)	–	2,762,248	3,714,601
54	Extraordinary Property Losses (182)	220		
55	Prelim. Survey and Investigation Charges (Electric) (183)	–	9,639,695	10,496,180
56	Prelim. Sur. and Invest. Charges (Gas) (183.1, 183.2)	–		
57	Clearing Accounts (184)	–	43,049	217,800
58	Temporary Facilities (185)	–		
59	Miscellaneous Deferred Debits (186)	223	6,056,445	53,544,532
60	Def. Losses from Disposition of Utility Plt. (187)	–		
61	Research, Devel. and Demonstration Expend. (188)	352–353	322	
62	Unamortized Loss on Reacquired Debt (189)	–		75,844
63	Accumulated Deferred Income Taxes (190)	224		
64	Unrecovered Purchased Gas Costs (191)	–		
65	Unrecovered Incremental Gas Costs (192.1)	–		
66	Unrecovered Incremental Surcharges (192.2)	–		
67	TOTAL Deferred Debits *(Enter Total of lines 53 thru 66)*		18,501,759	68,048,957
68	TOTAL Assets and other Debits *(Enter Total of lines 10, 11, 12, 21, 51, and 67)*		1,069,174,763	1,227,312,539

Reference is made to Notes to Financial Statements.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
The Washington Water Power Company	(1) [X] An Original (2) [ ] A Resubmission	April 30, 1984	Dec. 31, 19 83

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Omit Cents: Balance at Beginning of Year (c)	Omit Cents: Balance at End of Year (d)
1	PROPRIETARY CAPITAL			
2	Common Stock Issued (201)	250	316,185,662	362,031,658
3	Preferred Stock Issued (204)	250	95,000,000	95,000,000
4	Capital Stock Subscribed (202, 205)	251		
5	Stock Liability for Conversion (203, 206)	251		
6	Premium on Capital Stock (207)	251		
7	Other Paid-In Capital (208-211)	252		
8	Installments Received on Capital Stock (212)	251	52,746	49,805
9	(Less) Discount on Capital Stock (213)	253		
10	(Less) Capital Stock Expense (214)	253	1,858,296	2,016,200
11	Retained Earnings (215, 215.1, 216)	118-119	68,946,475	77,774,374
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	16,171,568	17,441,219
13	(Less) Reacquired Capital Stock (217)	250		
14	TOTAL Proprietary Capital *(Enter Total of lines 2 thru 13)*	–	494,498,155	550,280,856
15	LONG-TERM DEBT			
16	Bonds (221)	256	355,588,000	410,135,000
17	(Less) Reacquired Bonds (222)	256		
18	Advances from Associated Companies (223)	256		
19	Other Long-Term Debt (224)	256	120,892,394	157,461,121
20	Unamortized Premium on Long-Term Debt (225)		609,521	575,456
21	(Less) Unamortized Discount on Long-Term Debt-Dr. (226)			428,387
22	TOTAL Long-Term Debt *(Enter Total of lines 16 thru 21)*	–	477,089,915	567,743,190
23	CURRENT AND ACCRUED LIABILITIES			
24	Notes Payable (231)	–	(1)	
25	Accounts Payable (232)	–	20,088,054	17,849,112
26	Notes Payable to Associated Companies (233)	–	2,053,000	2,147,000
27	Accounts Payable to Associated Companies (234)	–	81,841	56,300
28	Customer Deposits (235)	–	241,963	303,306
29	Taxes Accrued (236)	258-259	10,983,076	6,617,124
30	Interest Accrued (237)	–	12,017,130	15,945,628
31	Dividends Declared (238)	–		
32	Matured Long-Term Debt (239)	–		
33	Matured Interest (240)	–		
34	Tax Collections Payable (241)	–	36,445	23,757
35	Miscellaneous Current and Accrued Liabilities (242)	–	3,135,793	4,245,630
36	TOTAL Current and Accrued Liabilities *(Enter Total of lines 24 thru 35)*		48,637,302	47,187,857

(1) Commercial Paper Financing in account 231 has been reclassified and is included in Long-Term Debt on line 19.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
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COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS) (Continued)

Line No.	Title of Account (a)	Ref. Page No. (b)	Balance at Beginning of Year (c) (Omit Cents)	Balance at End of Year (d) (Omit Cents)
37	DEFERRED CREDITS			
38	Customer Advances for Construction (252)		239,555	485,386
39	Accumulated Deferred Investment Tax Credits (255)	264	43,751,956	39,317,877
40	Deferred Gains from Disposition of Utility Plant (256)			
41	Other Deferred Credits (253)	266	2,225,386	2,715,928
42	Unamortized Gain on Reacquired Debt (257)			
43	Accumulated Deferred Income Taxes (281-283)	268-273	2,732,494	19,581,445
44	TOTAL Deferred Credits *(Enter Total of lines 38 thru 43)*		48,949,391	62,100,636
45	OPERATING RESERVES			
46	Property Insurance Reserve (261)			
47	Injuries and Damages Reserve (262)			
48	Pensions and Benefits Reserve (263)			
49	Miscellaneous Operating Reserves (265)			
50	TOTAL Operating Reserves *(Enter Total of lines 46 thru 49)*			
51				
52				
53				
54				
55				
56				
57				
58				
59				
60				
61				
62				
63				
64				
65				
66				
67				
68	TOTAL Liabilities and Other Credits *(Enter Total of lines 14, 22, 36, 44 and 50)*		1,069,174,763	1,227,312,539

Reference is made to Notes to Financial Statements.

Attachment 5-4
Forecasts and Backcasts of Average System Costs and Loads for FY 2002 Through 2008
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
The Washington Water Power Company	(1) [X] An Original (2) [ ] A Resubmission	April 30, 1984	Dec. 31, 19 83

STATEMENT OF INCOME FOR THE YEAR

1. Report amounts for accounts 412 and 413, *Revenue and Expenses from Utility Plant Leased to Others,* in another utility column (i, k, m, o) in a similar manner to a utility department. Spread the amount(s) over lines 01 thru 20 as appropriate. Include these amounts in columns (c) and (d) totals.
2. Report amounts in account 414, *Other Utility Operating Income,* in the same manner as accounts 412 and 413 above.
3. Report data for lines 7, 9, and 10 for Natural Gas companies using accounts 404.1, 404.2, 404.3, 407.1, and 407.2.
4. Use page 122 for important notes regarding the statement of income or any account thereof.
5. Give concise explanations concerning unsettled rate proceedings where a contingency exists such that refunds of a material amount may need to be made to the utility's customers or which may result in a material refund to the utility with respect to power or gas purchases. State for each year affected the gross revenues or costs to which the contingency relates and the tax effects together with an explanation of the major factors which affect the rights of the utility to retain such revenues or recover amounts paid with respect to power and gas purchases.
6. Give concise explanations concerning significant amounts of any refunds made or received during the year resulting from

Line No.	Account (a)	(Ref.) Page No. (b)	TOTAL Current Year (c)	TOTAL Previous Year (d)
1	UTILITY OPERATING INCOME			
2	Operating Revenues (400)		338,812,374	346,852,831
3	Operating Expenses			
4	Operation Expenses (401)		210,973,929	211,354,945
5	Maintenance Expenses (402)		9,424,554	10,494,687
6	Depreciation Expense (403)		16,234,317	15,272,381
7	Amort. & Depl. of Utility Plant (404–405)		4,197	4,197
8	Amort. of Utility Plant Acq. Adj. (406)			
9	Amort. of Property Losses (407)			
10	Amort. of Conversion Expenses (407)			
11	Taxes Other Than Income Taxes (408.1)	258	24,270,492	20,470,053
12	Income Taxes – Federal (409.1)	258	(9,020,264)	1,897,236
13	– Other (409.1)	258	(155,527)	303,895
14	Provision for Deferred Inc. Taxes (410.1)	224,268-273	16,877,306	1,962,965
15	(Less) Provision for Deferred Income Taxes–Cr. (411.1)	224,268-273		
16	Investment Tax Credit Adj. – Net (411.4)	264	(4,434,079)	12,390,643
17	(Less) Gains from Disp. of Utility Plant (411.6)			
18	Losses from Disp. of Utility Plant (411.7)			
19	TOTAL Utility Operating Expenses *(Enter Total of lines 4 thru 18)*		264,174,925	274,151,002
20	Net Utility Operating Income *(Enter Total of line 2 less 19) (Carry forward to page 117, line 21)*		74,637,449	72,701,829

Reference is made to Notes to Financial Statements.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
The Washington Water Power Company	(1) [X] An Original (2) [ ] A Resubmission	April 30, 1984	Dec. 31, 19 83

STATEMENT OF INCOME FOR THE YEAR (Continued)

settlement of any rate proceeding affecting revenues received or costs incurred for power or gas purchases. State the accounting treatment accorded such refunds and furnish the necessary particulars (details), including income tax effects, so that corrections of prior Income and Retained Earnings Statements and Balance Sheets may be made if needed; or furnish amended financial statements if that be deemed more appropriate by the utility.

7. If any notes appearing in the report to stockholders are applicable to this Statement of Income, such notes may be attached at page 122.

8. Enter on page 122 a concise explanation of only those changes in accounting methods made during the year which had an effect on net income, including the basis of allocations and apportionments from those used in the preceding year. Also give the approximate dollar effect of such changes.

9. Explain in a footnote if the previous year's figures are different from that reported in prior reports.

10. If the columns are insufficient for reporting additional utility departments, supply the appropriate account titles, lines 1 to 19, and report the information in the blank space on page 122 or in a supplemental statement.

ELECTRIC UTILITY		GAS UTILITY		STEAM UTILITY		Line No.
Current Year (e)	Previous Year (f)	Current Year (g)	Previous Year (h)	Current Year (i)	Previous Year (j)	
						1
215,450,732	205,340,578	120,580,187	134,889,156	2,438,485	4,178,159	2
						3
106,834,535	88,816,787	102,242,289	118,669,797	1,769,764	3,112,510	4
8,736,802	9,493,179	578,919	638,469	69,651	133,999	5
13,748,267	12,751,890	2,338,459	2,175,167	104,272	106,493	6
4,197	4,197					7
						8
						9
						10
18,536,744	14,704,630	5,660,105	5,201,556	138,792	273,525	11
(9,141,877)	304,315	120,367	1,401,918	(669)	111,027	12
(132,223)	330,145	(23,304)	(26,250)			13
16,700,612	1,827,226	135,573	94,207	32,427	27,217	14
						15
(3,962,985)	11,995,217	(106,341)	288,493	(647)	15,925	16
						17
						18
151,324,072	140,227,586	110,946,067	128,443,357	2,113,590	3,780,696	19
64,126,660	65,112,992	9,634,120	6,445,799	324,855	397,463	20

Reference is made to Notes to Financial Statements.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
The Washington Water Power Company	(1) [X] An Original (2) [ ] A Resubmission	April 30, 1984	Dec. 31, 1983

STATEMENT OF INCOME FOR THE YEAR (Continued)

Line No.	WATER UTILITY Current Year (k)	Previous Year (l)	OTHER UTILITY Current Year (m)	Previous Year (n)	OTHER UTILITY Current Year (o)	Previous Year (p)
1						
2	342,970	2,444,938				
3						
4	127,341	755,851				
5	39,182	229,040				
6	43,319	238,831				
7						
8						
9						
10						
11	(65,149)	290,342				
12	1,915	79,976				
13						
14	8,694	14,315				
15						
16	(364,106)	91,008				
17						
18						
19	(208,804)	1,699,363				
20	551,774	745,575				

Reference is made to Notes to Financial Statements.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
The Washington Water Power Company	(1) [X] An Original (2) [ ] A Resubmission	April 30, 1984	Dec. 31, 19 83

STATEMENT OF INCOME FOR THE YEAR (Continued)

Line No.	Account (a)	Ref. Page No. (b)	TOTAL Current Year (c)	TOTAL Previous Year (d)
21	Net Utility Operating Income *(Carried forward from page 114)*	–	74,637,449	72,701,829
22	Other Income and Deductions			
23	Other Income			
24	Nonutility Operating Income			
25	Revenues From Merchandising, Jobbing and Contract Work (415)		31	100
26	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)		57	182
27	Revenues From Nonutility Operations (417)			
28	(Less) Expenses of Nonutility Operations (417.1)			
29	Nonoperating Rental Income (418)		8,139	6,244
30	Equity in Earnings of Subsidiary Companies (418.1)	–	6,104,751	5,773,146
31	Interest and Dividend Income (419)		1,845,108	6,546,481
32	Allowance for Other Funds Used During Construction (419.1)	–	19,991,351	10,249,339
33	Miscellaneous Nonoperating Income (421)		65,340	427,675
34	Gain on Disposition of Property (421.1)		80,895	58,723
35	TOTAL Other Income *(Enter Total of lines 25 thru 34)*	–	28,095,558	23,061,526
36	Other Income Deductions			
37	Loss on Disposition of Property (421.2)		916,103	312,282
38	Miscellaneous Amortization (425)	337		
39	Miscellaneous Income Deductions (426.1-426.5)	337	415,740	347,152
40	TOTAL Other Income Deductions *(Total of lines 37 thru 39)*	–	1,331,843	659,434
41	Taxes Applic. to Other Income and Deductions			
42	Taxes Other Than Income Taxes (408.2)	258		
43	Income Taxes–Federal (409.2)	258	(14,521)	5,241,143
44	Income Taxes–Other (409.2)	258	(1,962)	182,354
45	Provision for Deferred Inc. Taxes (410.2)	224,268-273		
46	(Less) Provision for Deferred Income Taxes–Cr. (411.2)	224,268-273		
47	Investment Tax Credit Adj.–Net (411.5)			
48	(Less) Investment Tax Credits (420)			
49	TOTAL Taxes on Other Inc. and Ded. *(Enter Total of 42 thru 48)*	–	(16,483)	5,423,497
50	Net Other Income and Deductions *(Enter Total of lines 35, 40, 49)*	–	26,780,198	16,978,595
51	Interest Charges			
52	Interest on Long-Term Debt (427)	–	50,753,640	40,214,773
53	Amort. of Debt Disc. and Expense (428)		581,549	610,683
54	Amortization of Loss on Reacquired Debt (428.1)			
55	(Less) Amort. of Premium on Debt-Credit (429)		34,065	46,206
56	(Less) Amortization of Gain on Reacquired Debt-Credit (429.1)			
57	Interest on Debt to Assoc. Companies (430)	337	242,127	505,263
58	Other Interest Expense (431)	337	1,682,078	1,850,607
59	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)	–	19,514,922	12,300,634
60	Net Interest Charges *(Enter Total of lines 52 thru 59)*	–	33,710,407	30,834,486
61	Income Before Extraordinary Items *(Enter Total of lines 21, 50 and 60)*	–	67,707,240	58,845,938
62	Extraordinary Items			
63	Extraordinary Income (434)			
64	(Less) Extraordinary Deductions (435)			
65	Net Extraordinary Items *(Enter Total of line 63 less line 64)*	–		
66	Income Taxes–Federal and Other (409.3)	258		
67	Extraordinary Items After Taxes *(Enter Total of line 65 less line 66)*	–		
68	Net Income *(Enter Total of lines 61 and 67)*		67,707,240	58,845,938

Reference is made to Notes to Financial Statements.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
The Washington Water Power Company	(1) [X] An Original (2) [ ] A Resubmission	April 30, 1984	Dec. 31, 1983

STATEMENT OF RETAINED EARNINGS FOR THE YEAR

1. Report all changes in appropriated retained earnings, unappropriated retained earnings, and unappropriated undistributed subsidiary earnings for the year.
2. Each credit and debit during the year should be identified as to the retained earnings account in which recorded (Accounts 433, 436-439 inclusive). Show the contra primary account affected in column (b).
3. State the purpose and amount for each reservation or appropriation of retained earnings.
4. List first Account 439, *Adjustments to Retained Earnings,* reflecting adjustments to the opening balance of retained earnings. Follow by credit, then debit items, in that order.
5. Show dividends for each class and series of capital stock.
6. Show separately the state and federal income tax effect of items shown for Account 439, *Adjustments to Retained Earnings.*
7. Explain in a footnote the basis for determining the amount reserved or appropriated. If such reservation or appropriation is to be recurrent, state the number and annual amounts to be reserved or appropriated as well as the totals eventually to be accumulated.
8. If any notes appearing in the report to stockholders are applicable to this statement, attach them at page 122.

Line No.	Item (a)	Contra Primary Account Affected (b)	Amount (c)
	UNAPPROPRIATED RETAINED EARNINGS (Account 216)		
1	Balance — Beginning of Year		67,990,648
2	Changes *(Identify by prescribed retained earnings accounts)*		
3	Adjustments to Retained Earnings (Account 439)		
4	Credit:		
5	Credit:		
6	Credit:		
7	Credit:		
8	Credit:		
9	TOTAL Credits to Retained Earnings (Account 439) *(Enter Total of lines 4 thru 8)*		None
10	Debit:		
11	Debit:		
12	Debit:		
13	Debit:		
14	Debit:		
15	TOTAL Debits to Retained Earnings (Account 439) *(Enter Total of lines 10 thru 14)*		None
16	Balance Transferred from Income (Account 433 less Account 418.1)		61,602,489
17	(Less) Appropriations of Retained Earnings (Account 436)		
18			
19			
20			
21			
22	TOTAL Appropriations of Retained Earnings (Account 436) *(Enter Total of lines 18 thru 21)*		None
23	Dividends Declared — Preferred Stock (Account 437)		
24	$ 9.00 Series A	238	2,250,000
25	$12.96 Series B	238	3,888,000
26	$12.875 Series C	238	1,931,250
27	$15.00 Series D	238	3,750,000
28			
29	TOTAL Dividends Declared—Preferred Stock (Account 437) *(Enter Total of lines 24 thru 28)*		11,819,250
30	Dividends Declared — Common Stock (Account 438)		
31	Common Stock $2.48 per share	238	45,790,440
32			
33			
34			
35			
36	TOTAL Dividends Declared—Common Stock (Account 438) *(Enter Total of lines 31 thru 35)*		45,790,440
37	Transfers from Acct. 216.1, Unappropriated Undistributed Subsidiary Earnings		4,835,100
38	Balance — End of Year *(Enter Total of lines 01, 09, 15, 16, 22, 29, 36 and 37)*		76,818,547

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
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STATEMENT OF RETAINED EARNINGS FOR THE YEAR (Continued)

Line No.	Item (a)	Amount (b)
	APPROPRIATED RETAINED EARNINGS (Account 215) State balance and purpose of each appropriated retained earnings amount at end of year and give accounting entries for any applications of appropriated retained earnings during the year.	
39		
40		
41		
42		
43		
44		
45	TOTAL Appropriated Retained Earnings (Account 215)	None
	APPROPRIATED RETAINED EARNINGS-AMORTIZATION RESERVE, FEDERAL (Account 215.1) State below the total amount set aside through appropriations of retained earnings, as of the end of the year, in compliance with the provisions of Federally granted hydroelectric project licenses held by the respondent. If any reductions or changes other than the normal annual credits hereto have been made during the year, explain such items in a footnote.	
46	TOTAL Appropriated Retained Earnings-Amortization Reserve, Federal (Account 215.1)	955,827
47	TOTAL Appropriated Retained Earnings (Accounts 215, 215.1)	955,827
48	TOTAL Retained Earnings (Account 215, 215.1, 216)	77,774,374
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account 216.1)	
49	Balance – Beginning of Year (Debit or Credit)	16,171,568
50	Equity in Earnings for Year (Credit) (Account 418.1)	6,104,751
51	(Less) Dividends Received (Debit)	4,835,100
52	Other Changes *(Explain)*	
53	Balance – End of Year	17,441,219

Attachment 5-4
Forecasts and Backcasts of Average System Costs and Loads for FY 2002 Through 2008
WP-07-E-BPA-83

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
The Washington Water Power Company	(1) [X] An Original (2) [ ] A Resubmission	April 30, 1984	Dec. 31, 19 83

STATEMENT OF CHANGES IN FINANCIAL POSITION

1. This statement is not restricted to those items which are noncurrent in nature. It is intended that this statement be flexible enough in nature so that latitude can be given, under the classification of "Other," to allow for disclosure of all significant changes and transactions, whether they are within or without the current asset and liability groups.
2. If the notes to the funds statement in the respondent's annual report to stockholders are applicable in every respect to this statement, such notes should be attached to page 122.
3. Under "Other" specify significant amounts and group others.
4. Codes Used:
   (a) Such as net increase-decrease in working capital, etc., other than changes in short term investments shown as item 4(e).
   (b) Bonds, debentures and other long-term debt.
   (c) Net proceeds or payments.
   (d) Include commercial paper.
   (e) Identify separately such items as investments, fixed assets, intangibles, etc.
5. Enter on page 122 clarifications and explanations.

Line No.	SOURCES OF FUNDS *(See instructions for explanation of codes)* *(a)*	Amounts *(b)*
1	Funds from Operations	
2	Net Income	67,707,240
3	Principal Non-Cash Charges (Credits) to Income	
4	Depreciation and Depletion	16,875,632
5	Amortization of *(Specify)* Weatherization grants; debt discount expense & premium	2,057,402
6	Provision for Deferred or Future Income Taxes (Net)	16,877,306
7	Investment Tax Credit Adjustments	(4,434,079)
8	(Less) Allowance for Other Funds Used During Construction	39,506,273
9	Other (Net)	
10	Equity in Undistributed Earnings of Subsidiary Companies	(1,151,499)
11	Cash Dividends	(57,609,690)
12		
13		
14		
15		
16		
17	TOTAL Funds from Operations *(Enter Total of lines 2 thru 16)*	816,039
18	Funds from Outside Sources (New Money)	
19	Long-Term Debt (b) (c) - First Mortgage Bonds	60,000,000
20	Preferred Stock (c)	-0-
21	Common Stock (c)	45,843,055
22	Net Increase in Short-Term Debt (d)	19,500,000
23	Other (Net)	
24	Proceeds of Pollution Control Revenue Bonds	76,203,844
25	Redemption of Pollution Control Revenue Bonds	(60,000,000)
26	Kettle Falls Project Financing	(1,000,000)
27	Redemption of Sinking Fund Debentures	(5,000,000)
28		
29		
30		
31	TOTAL Funds from Outside Sources *(Enter Total of lines 19 thru 30)*	135,546,899
32	Sale of Non-Current Assets (e)	
33	Sale of Water System Properties	9,129,222
34	Contributions from Associated and Subsidiary Companies	
35	Other (Net) (a)	
36	(Increase) in Working Capital Components	(4,539,543)
37	Changes in Other Noncurrent Balance Sheet Items	5,521,744
38		
39		
40		
41		
42		
43	TOTAL Sources of Funds *(Enter Total of lines 17, 31, 32 thru 42)*	146,474,361

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
The Washington Water Power Company	(1) [X] An Original (2) [ ] A Resubmission	April 30, 1984	Dec. 31, 19 83

STATEMENT OF CHANGES IN FINANCIAL POSITION (Continued)

Line No.	APPLICATION OF FUNDS (a)	Amounts (b)
44	Construction and Plant Expenditures (Including Land)	
45	Gross Additions to Utility Plant (Less Nuclear Fuel)	166,930,490
46	Gross Additions to Nuclear Fuel	1,008,132
47	Gross Additions to Common Utility Plant	
48	Gross Additions to Nonutility Plant	
49	(Less) Allowance for Other Funds Used During Construction	39,506,273
50	Other	
51	TOTAL Applications to Construction and Plant Expenditures (Including Land) *(Enter Total of lines (45 thru 50)*	128,432,349
52	Dividends on Preferred Stock (See Page 120 Line 11.)	
53	Dividends on Common Stock (See Page 120 Line 11.)	
54	Funds for Retirement of Securities and Short-Term Debt	
55	Long-term Debt (b) (c)	453,000
56	Preferred Stock (c)	
57	Redemption of Capital Stock	
58	Net Decrease in Short-term Debt (d)	
59	Other (Net)	
60	Notes Payable - Other	122,162
61		
62		
63		
64		
65		
66	Purchase of Other Non-Current Assets (e)	
67		
68		
69	Investments in and Advances to Associated and Subsidiary Companies	1,321,215
70	Other (Net) (a):	
71	Weatherization Grants and Loans - Net	9,289,150
72	Preliminary Survey and Investigation Charges	856,485
73	Notes Receivable on Water System Sale	6,000,000
74		
75		
76		
77		
78	TOTAL Applications of Funds *(Enter Total of lines 51 thru 77)*	146,474,361

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
The Washington Water Power Company	(1) [X] An Original (2) [ ] A Resubmission	April 30, 1984	Dec. 31, 1983

NOTES TO FINANCIAL STATEMENTS

1. Use the space below for important notes regarding the Balance Sheet, Statement of Income for the year, Statement of Retained Earnings for the year, and Statement of Changes in Financial Position, or any account thereof. Classify the notes according to each basic statement, providing a subheading for each statement except where a note is applicable to more than one statement.

2. Furnish particulars (details) as to any significant contingent assets or liabilities existing at end of year, including a brief explanation of any action initiated by the Internal Revenue Service involving possible assessment of additional income taxes of material amount, or of a claim for refund of income taxes of a material amount initiated by the utility. Give also a brief explanation of any dividends in arrears on cumulative preferred stock.

3. For Account 116, *Utility Plant Adjustments*, explain the origin of such amount, debits and credits during the year, and plan of disposition contemplated, giving references to Commission orders or other authorizations respecting classification of amounts as plant adjustments and requirements as to disposition thereof.

4. Where Accounts 189, *Unamortized Loss on Reacquired Debt*, and 257, *Unamortized Gain on Reacquired Debt*, are not used, give an explanation, providing the rate treatment given these items. See General Instruction 17 of the Uniform Systems of Accounts.

5. Give a concise explanation of any retained earnings restrictions and state the amount of retained earnings affected by such restrictions.

6. If the notes to financial statements relating to the respondent company appearing in the annual report to the stockholders are applicable and furnish the data required by instructions above and on pages 114-121, such notes may be attached hereto.

Gains or losses on reacquisition of long-term debt to fulfill sinking fund requirements are recognized in the period of reacquisition and recorded in Account 421, Miscellaneous Nonoperating Income. This method of accounting is in accordance with the ratemaking treatment allowed in the Respondent's primary rate jurisdictions.

See Notes to Financial Statements appearing on the following Pages 122-A through 122-U.

THE WASHINGTON WATER POWER COMPANY

NOTES TO FINANCIAL STATEMENTS

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

SYSTEM OF ACCOUNTS

The accounting records of the Company are maintained in accordance with the uniform system of accounts prescribed by the Federal Energy Regulatory Commission (FERC) and adopted by the appropriate State regulatory commissions.

BASIS OF REPORTING

The accompanying financial statements include the Company's proportionate share of utility plant and related operations resulting from its interests in jointly owned plants (see Note 10).

The Company accounts for its investments in nonutility subsidiary companies on the equity method, whereby earnings or losses of these subsidiaries are reflected in other income on a one-month lag and added to or deducted from the cost of investments in the balance sheet. Dividends received from subsidiaries are deducted from the carrying value of investments. At December 31, 1983 the Company's retained earnings included undistributed earnings of these subsidiaries of $17,311,000. During 1983, 1982, and 1981 the Company received $4,835,000, $3,607,000, and $3,514,000, respectively, in dividends from its principal nonutility subsidiary, Washington Irrigation & Development Company (WIDCo). For a description of WIDCo's dividend payment restrictions and other information about WIDCo see Note 7.

UTILITY PLANT

The cost of additions to utility plant, including an allowance for funds used during construction and replacements of units of property and betterments, is capitalized. Maintenance and repairs of property and replacements determined to be less than units of property are charged to operating expenses. Costs of depreciable units of property retired plus costs of removal less salvage are charged to accumulated depreciation.

On February 28, 1983, the Company sold its water properties for $9,129,000, which approximated the book value of the properties. The operations of the water system were not material to the Company's Financial Statements.

ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION

The Allowance for Funds Used During Construction (AFUDC) represents the cost of both the debt and equity funds used to finance utility plant additions during the construction period. In accordance with the uniform system of accounts prescribed by regulatory authorities, AFUDC is capital-

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

ized as a part of the cost of utility plant and is credited as a noncash item to other income and interest charges currently. The Company is permitted, under established regulatory rate practices, to recover the capitalized AFUDC and a fair return thereon through its inclusion in rate base and the provision for depreciation after the related utility plant has been placed in service. Cash inflow related to AFUDC does not occur until the related utility plant is placed in service.

The Washington Utilities and Transportation Commission has approved the inclusion of a portion of construction work in progress ("CWIP") related to the Colstrip Project in rate base during 1983 pursuant to its rate order issued in December 1982. Inclusion of utility plant under construction in rate base proportionately reduces AFUDC and increases the current internal generation of cash, but does not have a material effect on net income. In accordance with an order of the Idaho Public Utilities Commission ("IPUC"), the Company discontinued capitalization of AFUDC on expenditures related to the Skagit Nuclear Project beginning January 1, 1982. In addition, the IPUC issued an order on January 5, 1984 ordering utilities to discontinue the practice of capitalizing AFUDC and which would allow utilities to include CWIP in rate base (see Note 9 for a discussion related to this matter).

The rates used for computing AFUDC were 12.20% in 1983, and 12.00% in 1982 and 1981. Effective July 1, 1981, the Company began semi-annual compounding of AFUDC as allowed by FERC. The Company's AFUDC rates do not exceed the maximum allowable rates as determined in compliance with a formula prescribed by FERC. The Company's AFUDC rate related to the Kettle Falls Project financing is computed at the actual cost thereon (see Note 4).

WEATHERIZATION PROGRAM

The weatherization program is a part of the Company's conservation efforts. The Company's investment in the program is carried at cost. The program consists of interest-free loans and grants made to customers for insulation and other heat saving modifications of existing electric heat homes. The loans are due within ten years of issuance or upon sale of the residence, whichever occurs first. The grants are being amortized to operating expenses over periods of from six to ten years.

DEPRECIATION

Depreciation provisions are computed by a method of depreciation accounting utilizing unit rates for electric hydro production plants and composite rates for other properties. Such rates are designed to provide for retirements of properties at the expiration of their service lives. The rates for electric hydro production plants include annuity and interest components, in which the interest component is 6%. The ratio of depreciation provisions to average depreciable property was 2.28% in 1983, and 2.21% in 1982 and 1981.

THE WASHINGTON WATER POWER COMPANY
NOTES TO FINANCIAL STATEMENTS

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

OPERATING REVENUES

Operating revenues are included in income as billed monthly to customers on a cycle billing basis.

RETIREMENT PLAN

The Company has a noncontributory Trusteed Retirement Plan covering its regular full-time employees. Pension costs are computed on the basis of accepted actuarial methods and include current service costs and amortization of prior service costs over 25 to 30 years. Total pension cost for 1983, 1982, and 1981 was $3,467,000, $3,629,000, and $3,255,000, respectively. For 1983, 1982, and 1981, $2,490,000, $2,675,000, and $2,309,000, respectively, of the costs were charged to operating expenses with the remainder being charged to construction and other accounts. The Company's policy is to make annual contributions to the pension plan equal to the amounts accrued for the cost of the pension. A comparison of accumulated plan benefits and plan net assets for the Company's pension plan as of January 1, 1983 and 1982 is presented below:

	January 1	
	1983	1982
	Thousands of Dollars	
Actuarial present value of accumulated plan benefits:		
Vested	$43,372	$38,230
Nonvested	1,097	1,613
Total	$44,469	$39,843
Net assets available for benefits	$44,926	$35,122

The weighted average assumed rate of return used in determining the actuarial present value of accumulated plan benefits was 7.5% for 1983 and 6.5% for 1982.

INCOME TAXES

Provisions for income taxes are based generally on income and expense as reported for financial statement purposes adjusted principally for AFUDC, certain expenses capitalized, earnings of subsidiaries, and the excess of tax depreciation over book depreciation.

Beginning with 1981 property additions, deferred income taxes are provided for the tax effect of Accelerated Cost Recovery System (ACRS) depreciation over straight-line depreciation. Investment tax credits generated are deferred and amortized over the useful life of the property. Prior to 1981, a portion of the investment tax credit allocable to the

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

State of Washington was "flowed through" to reduce Federal income tax expense of the current year.

With the exceptions noted above concerning ACRS depreciation and investment tax credits, the Company's tax provisions reflect the current tax reductions arising from timing differences. Such treatment is in accordance with requirements of regulatory authorities having jurisdiction over rates.

The Company and its subsidiaries file consolidated Federal income tax returns. Subsidiaries are charged or credited with the tax effects of their operations and investment tax credits. The Company's Federal income tax returns have been examined through 1979 with all issues resolved and all payments have been made through the 1977 return.

RETAINED EARNINGS

During a 60-month period ended February 1958, provisions for Federal income taxes gave effect to accelerated amortization, for tax purposes only, of 65% of the depreciable cost of the Cabinet Gorge Hydroelectric Project. Accounting for the resultant reductions in Federal income taxes was as prescribed by an order of the Washington Utilities and Transportation Commission. The order provided that during the 60-month period the reduction in taxes was to be segregated from net income and accumulated in an account entitled Retained Earnings-Restricted, and that the amount so accumulated be transferred ($542,000 annually) to retained earnings over the following 25-year period. As of December 31, 1982, the amount originally segregated in this account was fully transferred to Retained Earnings.

2. LONG-TERM DEBT

The aggregate annual sinking fund requirements and maturities for the five years through 1988 under the long-term debt outstanding at December 31, 1983, amount to: 1984, $4,100,000; 1985, $4,335,000; 1986, $4,500,000; 1987, $39,200,000; and 1988, $43,850,000. Of these annual amounts, $3,950,000 for the years 1984 through 1986; $3,650,000 for 1987; and $3,300,000 for 1988 may be met by certification of property additions at the rate of 167% of requirements. The Company intends to refinance the $50,000,000 of commercial paper and $1,000,000 of fixed term loans outstanding under its long-term financing arrangements.

All of the utility plant is subject to the lien of the mortgage and deed of trust securing outstanding First Mortgage Bonds.

On September 22, 1983, the Company sold $60,000,000 of 13 1/2% First Mortgage Bonds due September 1, 2013. On August 26, 1982, the Company received proceeds of $60,000,000 from the sale of 15-3/4% First Mortgage Bonds by a private placement. The bonds mature during the years 1990, 1991 and 1992. The proceeds of both issues were utilized to repay a portion of the Company's outstanding short-term debt originally incurred for the interim financing of new construction.

On December 1, 1983, $58,400,000 in principal amount of Annual Tender Pollution Control Revenue Bonds due December 1, 2013 was issued by the City of Forsyth, Montana, and invested in U.S. Treasury securities which were placed in a Trust for refunding the $60,000,000 principal amount of Pollution Control Revenue Bonds maturing June 1, 1984. For financial reporting purposes, the entire amount of debt ($60,000,000) satisfied by the assets placed in the trust is considered extinguished. The interest rate on the Annual Tender Pollution Control Bonds is adjusted annually on December 1 based upon an interest index. The interest rate for the first year was set at 6%. On a one-time basis, the Bonds are subject to conversion to a fixed interest rate for the remaining term of the Bonds. In the Company's financial statements, an amount equal to the principal amount of such revenue bonds, less the undisbursed trust funds available for construction expenditures and any investment earnings thereon, is shown as a liability.

3. BANK BORROWINGS AND COMMERCIAL PAPER

At December 31, 1983, the Company maintained total lines of credit with various banks under two separate credit agreements amounting to $150,000,000. The Company has a revolving line of credit expiring December 31, 1987, which provides a total credit commitment of $80,000,000 with $50,000,000 being utilized primarily as a backup bank line of credit for the Company's commercial paper. Under this agreement, the Company pays a facility fee of 3/8% per annum on $50,000,000 of the line and a commitment fee of 1/2% per annum on the daily average unused portion of the remaining $30,000,000. A second revolving credit agreement provides for up to $70,000,000 of notes to be outstanding at any one time. Under this agreement, the Company pays a commitment fee of

THE WASHINGTON WATER POWER COMPANY
NOTES TO FINANCIAL STATEMENTS

3. BANK BORROWINGS AND COMMERCIAL PAPER (Continued)

3/8% per annum on the daily average unused amount of the line with a provision that the commitment fee is reduced for credits received based on balances maintained at the banks.

In addition, under various agreements with banks, the Company can have up to $50,000,000 in loans outstanding at any one time, with the loans available at the banks' discretion. These arrangements provide, if funds are made available, for fixed term loans for up to 180 days at a fixed rate of interest.

Balances and interest rates of the various lines of credit, bank borrowings and commercial paper were as follows:

	Years Ended December 31		
	1983	1982	1981
	Thousands of Dollars		
Balance outstanding at end of period:			
Lines of credit	$ -	$ -	$63,000
Fixed term loans	1,000	-	-
Commercial paper	50,000	31,500	-
Maximum balance during period:			
Lines of credit	$ -	$63,000	$75,000
Fixed term loans	39,000	34,000	17,000
Commercial paper	50,000	50,000	-
Average daily balance during period:			
Lines of credit	$ -	$10,553	$38,795
Fixed term loans	7,136	12,814	2,906
Commercial paper	40,451	19,993	-
Average annual interest rate during period:			
Lines of credit	- %	16.27%	19.03%
Fixed term loans	10.14	14.26	14.82
Commercial paper	9.28	12.43	-
Average annual interest rate at end of period:			
Lines of credit	- %	- %	15.95%
Fixed term loans	10.50	-	-
Commercial paper	9.90	9.13	-

4. PROJECT FINANCING

On September 30, 1981, the Company completed arrangements for the construction financing of the Kettle Falls Project. The Company transferred to WP Energy Co., a wholly owned subsidiary of the Company, the construction work in progress relating to the plant and the real estate on which it is located. Under the financing arrangement, various banks agreed to make loans, up to a maximum of $100,000,000 (subsequently reduced to $75,000,000), to WP Energy Co. for construction of the plant which was completed in 1983, provided that the commitment of the banks to make loans terminates on September 30, 1984. On August 3, 1983 WP Energy Co. was merged into the Company and the Company assumed its obligations and rights under this agreement. The loans are repayable in installments according to a schedule commencing September 30, 1987 with the final payment to be made on September 30, 1991. At December 31, 1983, and 1982, $50,000,000 and $51,000,000, respectively, of bank loans were outstanding under these arrangements.

Interest on funds expended for construction of the Kettle Falls Project is capitalized based on the actual cost of the funds. In the financial statements, interest and related fees in the amount of $6,413,000, $3,999,000 and $329,000 for 1983, 1982 and 1981, respectively, are included in interest charges, offset by a like amount included in Allowance for Borrowed Funds Used During Construction.

5. PREFERRED STOCKS

Cumulative Preferred Stock Not Subject To Mandatory Redemption:

The $12.96 Preferred Stock, Series B, will not be refundable prior to February 1, 1985 with the proceeds of borrowed funds or of the issuance of any stock ranking prior to or on a parity with such series having a cost of money to the Company of less than 12.96% per annum. The preferred stock is otherwise subject to redemption at the Company's option at the following redemption prices per share, plus accrued dividends:

$9.00, Series A - $105.40 and $102.70 prior to May 1, 1988 and 1993, respectively, and $100.90 thereafter.

$12.96, Series B - $112.96, $107.77 and $103.88 prior to February 1, 1985, 1990 and 1995, respectively, and $101.00 thereafter.

Cumulative Preferred Stock Subject to Mandatory Redemption:

On April 27, 1982, the Company received $25,000,000 of proceeds from the sale of 250,000 shares of $15.00 Preferred Stock, Series D at a stated value of $100 per share. On August 25, 1981, the Company received $15,000,000 of proceeds from the sale of 150,000 shares of $12.875 Preferred Stock, Series C at a stated value of $100 per share.

5. PREFERRED STOCKS (Continued)

Redemption Requirements:

$12.875, Series C - On September 15, 1989, 1990, and 1991 the Company must redeem 50,000 shares at $100 per share plus accumulated dividends.

$15.00, Series D - On June 15, 1988, 1989, 1990, 1991 and 1992, the Company must redeem 50,000 shares at $100 per share plus accumulated dividends.

6. COMMON STOCK

The Company has an Employees' Stock Purchase Plan which provides for the granting to all regular employees of the Company and its principal subsidiaries, during such limited offering periods as may be specified from time to time by the Board of Directors, the right to purchase a limited number of shares of the Company's common stock, with the privilege of paying for such shares on an installment basis through payroll deductions.

The Company also has in effect a Payroll-Based Employee Stock Ownership Plan (PAYSOP) providing for the issuance and sale of common stock to a trust account for the benefit of its employees. This Plan was effective in 1983, with the first shares to be issued in 1984, and replaces the Tax Reduction Act Stock Ownership Plan (TRASOP) under which shares could last be issued in 1983. In addition, the Company has a Dividend Reinvestment and Stock Purchase Plan under which the Company's stockholders may automatically reinvest their dividends and make optional cash payments for the purchase of the Company's common stock.

Sales of common stock for 1983, 1982 and 1981 are summarized on the following page.

THE WASHINGTON WATER POWER COMPANY
NOTES TO FINANCIAL STATEMENTS

6. COMMON STOCK (Continued)

	1983		1982		1981	
	Shares	Amount Thousands of Dollars	Shares	Amount Thousands of Dollars	Shares	Amount Thousands of Dollars
Balance January 1......................	17,775,671	$316,238	13,638,280	$238,749	10,918,587	$194,505
Public Sale..........................	1,500,000	28,628	3,500,000	65,508	2,400,000	38,824
Employees' Stock Purchase Plan.......	21,843	409	31,749	509	41,544	682
Dividend Reinvestment Plan...........	625,371	12 751	472,254	8,935	188,512	3,228
TRASOP...............................	207,945	4,055	133,388	2,537	89,637	1,510
Total Issues.........................	2,355,159	45,843	4,137,391	77,489	2,719,693	44,244
Balance December 31..................	20,130,830	$362,081	17,775,671	$316,238	13,638,280	$238,749

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THE WASHINGTON WATER POWER COMPANY
NOTES TO FINANCIAL STATEMENTS

7. SUBSIDIARIES

Condensed financial information of the Company's principal nonutility subsidiary, Washington Irrigation & Development Company, as presented below is based on financial statements for the years ended November 30. This subsidiary owns an undivided one-half interest in coal mining properties near Centralia, Washington, which it operates and which supplies coal to the Centralia Steam Electric Generating Plant owned 15% by the Company.

	1983	1982	1981
	Thousands of Dollars		
Statements of Operations:			
Sales and revenues	$47,271	$42,899	$37,805
Costs and expenses	40,473	36,236	31,403
Income before Federal income tax	6,798	6,663	6,402
Federal income tax expense (a)	1,735	1,327	1,711
Net income	$ 5,063	$ 5,336	$ 4,691

	1983	1982
	Thousands of Dollars	
Balance Sheets:		
Assets:		
Centralia Coal Mining Project - net (b) (c)	$40,451	$37,208
Cash and other assets	7,450	8,557
Total	$47,901	$45,765
Liabilities:		
Capital stock	$14,200	$14,200
Retained earnings (c)	11,353	11,125
First mortgage bonds, 10-5/8% due 1989 (c)	3,305	4,010
Capital lease obligations	2,314	3,003
Bank loans	3,100	-
Other liabilities	8,425	9,526
Deferred income tax and investment tax credits	5,204	3,901
Total	$47,901	$45,765

7. SUBSIDIARIES (Continued)

(a) The provision for Federal income tax is different from that which would be computed by applying the statutory tax rate to income before income tax due to the use of percentage depletion of mineral properties.

(b) Plant and equipment are recorded at cost and depreciated over estimated useful lives utilizing straight-line and unit of production methods and exploration and development costs are depleted and amortized on the unit of production method.

(c) The project is subject to the lien of the mortgage securing Washington Irrigation & Development Company's first mortgage bonds. Under the mortgage, cash dividends paid and stock repurchases cannot exceed cumulative net income accrued subsequent to December 31, 1981. Also, an additional one million dollars per year may be paid out as dividends on a cumulative basis beginning in 1982, provided that the total of such payments does not exceed five million dollars.

8. FEDERAL INCOME TAXES

A reconciliation of Federal income taxes derived from statutory tax rates applied to income for accounting purposes and such taxes charged to operating expense is as follows:

	1983	1982	1981
	Thousands of Dollars		
Federal income tax expense at statutory rate............................	$ 32,713	$36,966	$27,105
Reductions in taxes from:			
Additional tax depreciation.................	(2,568)	(2,437)	(3,005)
Investment tax credit......................	(4,434)	(529)	(389)
Equity in earnings of subsidiary companies..	(2,808)	(2,656)	(2,385)
AFUDC capitalized..........................	(15,223)	(8,533)	(6,850)
Weatherization grant expenditures...........	(4,423)	(866)	-
Other timing differences....................	151	(453)	(1,079)
Total provision for income taxes.............	3,408	21,492	13,397
Charges to other income.....................	15	(5,241)	(2,949)
Federal income tax charged to operating expenses....................................	3,423	16,251	10,448
Deferred investment credit - net............	4,434	(16,603)	(7,940)
Provision for deferred income taxes.........	(3,912)	(1,963)	(770)
Taxes deferred on tax write-off of the Skagit Nuclear Project (see Note 9).............	(12,965)	-	-
Federal income tax payable from operations....	(9,020)	(2,315)	1,738
Federal income tax refund receivable........	4,944	-	-
Net Federal income tax currently payable from operations..............	$ (4,076)	$(2,315)	$ 1,738

8. FEDERAL INCOME TAXES (Continued)

The Company has unused investment tax credits of approximately $16,360,000 which may be carried forward and applied against future Federal income tax payments. These carry forwards will begin to expire if not used prior to 1997.

9. COMMITMENTS AND CONTINGENCIES

The Company's construction program for the years 1984 and 1985 (excluding AFUDC), subject to continuing review and adjustment, is estimated at $82,000,000 and $77,000,000, respectively, and the Company has substantial contractual commitments related thereto. These estimates do not reflect present and continuing reductions in capital expenditures for the Washington Public Power Supply System Project 3, which is currently in a construction delay (see "Washington Public Power Supply System Project 3"). The Company is unable to predict the extent to which governmental licensing, siting and environmental regulation, litigation and other factors affecting the construction program may result in delays, cost increases, or termination of projects under construction.

Washington Public Power Supply System Project 3.

General. The Washington Public Power Supply System ("WPPSS"), a joint operating agency and municipal corporation of the State of Washington, sponsored five nuclear projects. Projects 1, 2 and 4, located on the Hanford Reservation near Richland, Washington, are wholly owned by WPPSS. Projects 3 and 5, located near Satsop, Washington, are twin units. Project 3 is owned 70 percent by WPPSS and 30 percent by four investor-owned utilities, including the Company which has a 5 percent ownership interest. Project 5 is owned 90 percent by WPPSS and 10 percent by Pacific Power & Light Company ("PP&L"). The Company does not have an ownership interest in any WPPSS Project other than its 5 percent interest in Project 3. The Company's investment in Project 3 was $132.8 million (including $33.3 million of AFUDC) at December 31, 1983.

Construction of Projects 4 and 5 was terminated on January 22, 1982, due to the unavailability to WPPSS of financing. On May 1, 1982, construction of Project 1 was delayed for five years due to reduced load forecasts and financial considerations. On July 8, 1983, the WPPSS Executive Board approved the implementation of an immediate extended construction delay of Project 3, as described below. At that time construction of Project 3 was approximately 75 percent complete. Construction is nearly complete on Project 2 which is scheduled for commercial operation in mid-1984.

WPPSS entered into agreements with various publicly owned utilities, municipalities and cooperatives ("Participants") to sell WPPSS' share of the output of the WPPSS Projects. With respect to Projects 1, 2 and 3,

9. COMMITMENTS AND CONTINGENCIES (Continued)

WPPSS, the Bonneville Power Administration ("BPA") and the Projects 1, 2 and 3 Participants entered into net billing agreements ("Net Billing Agreements") whereby those Participants agreed to buy WPPSS' share of the output of those Projects and assigned such output to BPA. In return for the assignment, BPA agreed to make certain payments, including amounts in respect of debt service on bonds issued to finance WPPSS' share of the construction costs of Projects 1, 2 and 3, whether or not the Projects are completed. With respect to Projects 4 and 5, WPPSS entered into agreements with the Projects 4 and 5 Participants ("Participants' Agreements") whereby those Participants agreed to buy WPPSS' share of the output of those Projects. BPA is not a party to the Participants' Agreements and did not agree to pay construction or any other costs relating to Projects 4 and 5.

Effect on Project 3 of Litigation and WPPSS Default on 4 and 5 Bonds. There are numerous lawsuits in several states relating, among other things, to the validity and enforceability of the Participants' Agreements. The Washington Supreme Court and an Oregon trial court have held that municipal Participants in Projects 4 and 5 lacked authority to enter into the Participants' Agreements, thereby rendering the Participants' Agreements void and unenforceable as to such Participants and preventing them from paying WPPSS pursuant to those Agreements. As a consequence of those decisions, WPPSS admitted on July 25, 1983 that it could no longer satisfy Projects 4 and 5 obligations, including the debt service on the $2.25 billion in principal amount of bonds ("4 and 5 Bonds") issued to finance WPPSS' share of those Projects. Such admission resulted in an event of default on the 4 and 5 Bonds; and Chemical Bank, as trustee, has declared all such Bonds immediately due and payable. On September 26, 1983 the Idaho Supreme Court also held that the Idaho municipal Participants in Projects 4 and 5 lacked authority to enter into Participants' Agreements, thereby rendering the Participants' Agreements void and unenforceable as to such Participants.

In connection with the Net Billing Agreements, however, the United States District Court for the District of Oregon, on April 27, 1983, ruled that WPPSS, BPA and all the Projects 1, 2 and 3 Participants had the authority to enter into the Net Billing Agreements and that the United States, through BPA, bears the financial risk if Projects 1, 2 and 3 do not produce power. On July 11, 1983, a group of ratepayers from the City of Springfield, Oregon, filed an appeal of the District Court's decision in the United States Ninth Circuit Court of Appeals and on July 25, 1983, two Participants joined in that appeal.

Several lawsuits have been commenced in Federal and state courts by and on behalf of holders of the 4 and 5 Bonds against WPPSS and, in some instances, against Projects 4 and 5 Participants, underwriters and bond counsel, alleging, among other things, violations of securities laws in connection with the sale of the 4 and 5 Bonds.

9. COMMITMENTS AND CONTINGENCIES (Continued)

The foregoing developments, as well as concerns that creditors associated with Projects 4 and 5 may attempt to reach Project 3 assets, have rendered WPPSS unable at this time to sell bonds to finance its share of the remaining construction costs of Project 3.

Construction Delay of Project 3. In May 1983, a BPA study was presented to the WPPSS Executive Board. The study was designed to analyze the effects on BPA's customers of various schedules for construction of Project 3, based on BPA's current load and resource forecasts. As a result of that study, BPA proposed to WPPSS a three-year construction delay on Project 3. On May 27, 1983, as an interim measure, WPPSS implemented an immediate construction slowdown at Project 3 for 30 days while WPPSS sought financing for its share of the Project other than by the sale of bonds. WPPSS was unable to secure such financing, and on June 27, 1983, WPPSS proposed that the full construction costs of its share in Project 3 be paid by BPA out of current revenues. BPA rejected this proposal and on July 8, 1983, the WPPSS Executive Board stated that it was unaware of any current source of funds for continuing full or partial construction of Project 3 and implemented an immediate extended construction delay until an assured source of funding is obtained. The Company cannot predict when or if WPPSS financing will become available.

The Company opposes the three-year delay in construction recommended by BPA. The Company is pursuing its position in the United States District Court for the Western District of Washington and was joined initially in its claims by PP&L and the two other investor-owned utilities with ownership interests in Project 3. The Company seeks to have the Court enjoin WPPSS and BPA from delaying construction of Project 3 and has requested damages from BPA and WPPSS for the delay. On October 12, 1983, the Court ordered a stay of a motion made by the investor-owned utilities to enjoin WPPSS and BPA from delaying construction of Project 3 and ordered the establishment of a three-member arbitration board charged with the responsibility of determining whether the BPA proposal to delay construction of Project 3 for three years constituted a prudent utility practice. BPA contested the arbitration procedure and has filed a notice of appeal with the United States Ninth Circuit Court of Appeals. On January 6, 1984, the Board ruled that the proposal to delay Project 3 for 3 years would not have been a prudent utility practice assuming that funds for completion were available to WPPSS but that, in the absence of funds, it was prudent to defer construction. The Court has not yet ruled on whether funds were available to WPPSS from BPA current revenues.

On January 30, 1984, PP&L, which has a 10% ownership interest in Project 3, amended its pleadings to withdraw its request for an injunction to obtain restart of construction of Project 3, stating that Project 3 may no longer be economically viable from PP&L's point of view. PP&L also seeks to be excused from performance under the Ownership Agreement for Project 3 whether or not BPA or WPPSS are held to have breached their

9. COMMITMENTS AND CONTINGENCIES (Continued)

contractual obligations. The Company cannot predict what effect PP&L's position may have on the completion of Project 3 or when the litigation may be resolved.

Irrespective of the board's decision or the action which the Court may take in response thereto, a substantial delay of completion of Project 3 will occur as a result of the construction delay since June 1983. Continued postponement of restart of construction will further delay completion from January 1, 1988, the earliest possible completion date. The Company's most recent load forecasts filed with the Pacific Northwest Utilities Conference Committee on December 1, 1983, forecast that power from Project 3 would not be needed to serve the Company's firm system loads until 1990.

The cost of construction of the Company's share of Project 3 resulting from a three-year delay is estimated to increase by $129 million (consisting of mothballing costs, allowances for escalation and $93 million of additional AFUDC). Based on these estimates, the Company's share of Project 3 cost upon completion would be approximately $400 million, including AFUDC. However, there can be no assurance that there will not be additional delays and increased costs including those resulting from new regulations propounded during the deferral period.

At this time, the Company does not have a means of determining the damages, if any, which WPPSS and/or BPA would be required to pay due to the construction delay. Also, the Company cannot make an accurate assessment of the likely cost of completion of Project 3 to the Company. In addition, the Company is not able to accurately predict or assess its exposure to claims which could arise from termination of its participation in Project 3 without the consent or agreement of all other interested parties. In view of the inability of the Company to obtain immediate restart of construction and in light of the substantial increased costs of Project 3 and other risks, including the risk of termination, associated with delay, the Company is evaluating the continuing cost effectiveness of the Project. The Company's current study, while it cannot be conclusive in light of the uncertainties, shows that under certain conditions, completion of the Project may not be cost effective to the Company or to its customers. The Company is continuing to pursue settlement discussions with BPA relating to Project 3.

See "Ratemaking and Accounting Issues" for information relating to the ratemaking treatment which the Company would request in the event of a termination of Project 3 and the accounting if such treatment were disallowed.

Increased or Additional Costs to the Company. The Company may be obligated for claims by Project 3 contractors relating to the cessation of craft construction on June 1, 1983, as well as for work and materials provided during the construction delay at the request of WPPSS. The

9. COMMITMENTS AND CONTINGENCIES (Continued)

Company does not have sufficient information at this time to identify or estimate the amount of such claims and costs. The Company's share of WPPSS' proposed mothball budget for 1984 is approximately $5 million.

Irrespective of a construction delay, the completion cost of Project 3 will increase as a result of the termination of Project 5. The cost increase is due primarily to the loss of the economies which would have resulted from building twin projects and the common use of certain facilities. The Project 3 owners may have to reimburse Project 5 for a portion of the costs of such facilities and services previously paid for Project 5. There are several pending claims and lawsuits relating to the appropriate allocation between Projects 3 and 5 of previously paid costs of such facilities and services. In addition to increased costs due to the termination of Project 5, WPPSS has advised the Company that the Project 1 delay will increase the cost of overhead and similar expenditures for Project 3.

The Company has not agreed on the extent to which it may be obligated to share in the increased Project 3 costs resulting from either the termination of Project 5 or the construction delay of Project 1. The Company estimates that its share of such increased costs would not exceed $35 million, including approximately $2.9 million deposited with BPA, prior to WPPSS' decision to terminate Projects 4 and 5, in order to support a preservation of WPPSS' assets. (See "Ratemaking and Accounting Issues".)

Skagit Project. The Company has a 10% interest in the Skagit-Hanford Project ("Skagit"), a proposed nuclear power plant sponsored by Puget Sound Power & Light Company ("PSP&L"). In December 1983, the participants in Skagit formally terminated plans for its construction. At that time, the Company's investment in the Project amounted to $39.3 million (including $11.2 million of AFUDC). Additional costs could be incurred as the outstanding contracts associated with Skagit are terminated. Such additional costs cannot be reasonably estimated at this time, but are not expected to have a significant impact on the Company's share of the cost of Skagit.

The Company's investment in Skagit was claimed as a deduction for Federal income tax purposes during 1983, resulting in a reduction of current taxes payable. However, the impact on net income of the tax reduction has been deferred pending actions by the Washington Utilities and Transportation Commission ("WUTC") and the IPUC relating to the recoverability of the Skagit investment. (See below.)

Ratemaking and Accounting Issues. The Company will request during 1984 authorization from the WUTC and IPUC to amortize its investment in Skagit, as well as subsequent termination charges, over an appropriate period of years and to recover such investment through electric rates. In the event of the abandonment or termination of Project 3, the Company would make a similar request to the WUTC and the IPUC.

9. COMMITMENTS AND CONTINGENCIES (Continued)

On February 1, 1983 the WUTC, in a rate increase order relating to PP&L, recognized that it is generally appropriate for ratepayers to share with stockholders the responsibility and risk inherent in the financing of generating resources, but stated that there was no reason to protect stockholders from all such risks. In addition, on July 25, 1983, the WUTC authorized PSP&L to amortize over a ten-year period PSP&L's investment in an abandoned nucelar project. The WUTC denied PSP&L any return on the unamortized balance, stating that the Company's stockholders should bear some of the risks of abandoned projects. The Attorney General of the State of Washington has appealed the WUTC order regarding PSP&L in opposition to amortization. The Company has no ownership interest in the projects involved in these WUTC orders. The IPUC has not had occasion to rule on amortization of a terminated or an abandoned project and therefore the Company cannot predict what action the IPUC will take when requested to approve rate adjustments for recovery of terminated or abandoned projects.

In a rate order effective February 9, 1984, the IPUC excluded from the Company's rate base $30,290,000, the cost of the Kettle Falls Project allocable to Idaho. The IPUC concluded that the Kettle Falls Project was not economically useful to the Company and that the decision to build the project was imprudent. The Company will petition the IPUC for rehearing, and depending on the results of its petition, will appeal the IPUC's Order to the Idaho Supreme Court.

In accordance with generally accepted accounting principles, if a regulatory commission does not allow recovery of all or a portion of an investment in an abandoned or terminated project, the total amount which is not allowed to be recovered would be recorded as an expense in the period in which it becomes known that the recovery is disallowed. In the event Project 3 were terminated and recovery through increased rates of all or a substantial portion of the Company's investment was not allowed, the Company might be required to reduce or eliminate dividends and its ability to obtain external financing could be significantly impaired.

On October 27, 1983, the IPUC issued a Notice and Order which, among other matters, directed the Company in its pending electric rate case before the IPUC to rebut allegations to the effect that the Company should discontinue participation in Project 3. The IPUC Order stated that if the Company did not satisfactorily rebut the allegations the IPUC would consider certain actions, including directing the Company to discontinue the accumulation of AFUDC associated with Project 3. AFUDC associated solely with Project 3 for 1983 was $14,370,000 and represented 78¢ of the Company's $3.02 earnings per average share of Common Stock. The IPUC at the request of the Company removed issues relating to Project 3 from the pending rate case to a separate proceeding. Hearings are scheduled to commence February 14, 1984. The Company cannot predict what action the IPUC will take in regard to the Company's participation in Project 3.

9. COMMITMENTS AND CONTINGENCIES (Continued)

The Idaho Supreme Court on December 14, 1983, in Utah Power & Light Co. v. IPUC, ruled that the IPUC was in error in refusing to include CWIP and property held for future use in Utah Power & Light Co.'s rate base. On January 5, 1984, the IPUC issued an Order interpreting the Court's decision as mandating the inclusion of CWIP in rate base for all utilities, and ordering them to discontinue the accounting practice of accruing AFUDC, effective January 25, 1984. The Company petitioned the IPUC for rehearing and/or reconsideration and for a stay of its Order terminating the accumulation of AFUDC. The IPUC granted a stay of its Order for 60 days. Legislation, proposed by the IPUC, has been introduced in the Idaho Legislature restricting the inclusion of CWIP in a utility's rate base, but requiring accrual of AFUDC in the event CWIP is excluded.

Other Contingencies

The Company has long-term contracts for the purchase of electric power from Public Utility Districts with hydroelectric generating plants in Central Washington. The Company receives a percentage share of the output of the plants and pays a like percentage share of the expenses (including debt service charges) of the related projects. These contracts expire on various dates between 1995 and 2018. The Company also has various agreements for the purchase, sale or exchange of power with other utilities or agencies (see Note 11).

10. JOINTLY OWNED ELECTRIC FACILITIES

The Company is involved in several jointly owned generating plants, some in service, some under construction and some in the licensing phase. Financing for the Company's ownership in the projects is provided by the Company. The Company's share of related operating and maintenance expenses for plants in service is included in corresponding accounts in the Statements of Income. The following table indicates the Company's percentage ownership and the extent of the Company's investment in such plants at December 31, 1983:

10. JOINTLY OWNED ELECTRIC FACILITIES (Continued)

Project	Kw of Installed Capacity	Energy Source (Fuel)	Company's Share of Ownership(%)	Plant in Service	Accumulated Depreciation	Net Plant in Service	Construction Work in Progress
				Thousands of Dollars			
In service:							
Centralia..........	1,330,000	Coal	15%	$46,978	$14,477	$32,501	$ 45
Under construction:							
Colstrip 3.........	700,000	Coal	15				175,790(a)
Colstrip 4.........	700,000	Coal	15				73,776
WPPSS No. 3........	1,240,000	Nuclear(b)	5				132,844
In the licensing phase:							
Creston............	(c)	Coal	(c)				-

(a) Colstrip 3 was determined to be available for commercial operation on January 10, 1984 and was transferred to electric plant in service at that time.

(b) See Note 9 for a discussion related to WPPSS No. 3.

(c) The Company has a site certificate for the Creston project. Construction timing, annual construction expenditure levels, and ultimate size of the plant are subject to final determination of ownership participation, licensing, and resource requirements. The Company's costs of $10,393,000 related to this project (as of December 31, 1983) are included in preliminary survey and investigation charges.

THE WASHINGTON WATER POWER COMPANY
NOTES TO FINANCIAL STATEMENTS

11. LONG-TERM PURCHASED POWER CONTRACTS

Under fixed contracts with Public Utility Districts, the Company has agreed to purchase portions of the generating output of certain facilities. Although the Company has no investment in such facilities, these contracts provide that the Company pay certain minimum amounts (which are based at least in part on the debt service requirements of the supplier) whether or not the facility is operating. The cost of power obtained under the contracts, including payments made when a facility is not operating, is included in purchased power in the Statements of Income. Information as of December 31, 1983 pertaining to these and certain other contracts is summarized in the following table:

	Company's Current Share of					
	Output	Kilowatt Capability	Annual Costs(d)	Debt Service Costs(d)	Revenue Bonds Outstanding 8-31-83	Contract Expiration Date
			Thousands of Dollars			
Public Utility District (PUD) Contracts:						
Chelan County PUD:						
Lake Chelan Project....	100.0%(a)	58,000	$ 1,616	$ 933	$ 6,863	1995
Rocky Reach Project....	2.9	37,000	688	373	5,859	2011
Grant County PUD:						
Priest Rapids Project..	6.1	55,000	962	510	5,072	2005
Wanapum Project........	8.2	75,000	1,280	762	9,551	2009
Douglas County PUD:						
Wells Project..........	4.5 (b)	37,000	834	502	8,309	2018
Other Contracts:						
Columbia Storage Power Exchange (CSPE)........	5.0 (c)	65,000	833	833	6,602	2003
BPA......................	N/A (c)	39,000	191	-	N/A	2003
BPA (WPPSS Project No. 1).................	N/A	80,000	11,155	-	N/A	1996
Totals		446,000	$17,559	$3,913	$42,256	

N/A = Not Applicable

(a) The Company purchases the Lake Chelan Project output and sells back to the PUD about 30% of the output to supply local service area requirements.
(b) The Company's percentage of the output of the Wells Project may be reduced, after advance notice and in accordance with a predetermined schedule, which by 1988 could reduce the Company's percentage to 3.5% for the remainder of the contract term. The Douglas County PUD has been giving the required notices to accomplish this reduction.

11. LONG-TERM PURCHASED POWER CONTRACTS (Continued)

(c) As a result of construction of storage dams in Canada pursuant to a treaty between that country and the United States, the Company is receiving substantial firm power benefits from storage releases. Under an agreement, entitled "Canadian Entitlement Exchange Agreement", with CSPE, which purchased a share of the downstream benefits, the Company will receive 5% of CSPE's power and it will pay 5% of CSPE's costs. The Company's share of CSPE power will decrease each year and by 1986 the Company will receive 52,000 Kw. In connection with this arrangement, the Company purchases a specified amount of capacity from BPA which decreases annually to 28,000 Kw by 1986.

(d) The annual costs will change in proportion to the percentage of output allocated to the Company in a particular year. Amounts represent the debt service and operating costs for the year 1983.

Actual expenses for payments made under the above contracts for the years 1983, 1982 and 1981 were $17,559,000, $14,310,000, and $11,940,000, respectively. The estimated aggregate amounts of required minimum payments (the Company's share of debt service costs) under the above contracts for the years 1984 through 1988 are as follows: 1984, $3,844,000; 1985, $3,781,000; 1986, $3,726,000; 1987, $3,704,000; and 1988, $3,649,000. In addition, the Company will be required to pay its proportional share of the variable operating expenses of the projects.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
The Washington Water Power Company	(1) [X] An Original (2) [ ] A Resubmission	April 30, 1984	Dec. 31, 1983

SUMMARY OF UTILITY PLANT AND ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION

Line No.	Item (a)	Total (b)	Electric (c)	Gas (d)	Other (Specify) Steam Heat (e)	Other (Specify) Water (f)	Common (g)
1	UTILITY PLANT						
2	In Service						
3	Plant in Service (Classified)	820,948,975	733,829,390	83,420,139	3,699,446	-0-	
4	Plant Purchased or Sold					Sold to General	
5	Completed Construction not Classified					Waterworks Corp.	
6	Experimental Plant Unclassified					2/28/83	
7	TOTAL *(Enter Total of lines 3 thru 6)*	820,948,975	733,829,390	83,420,139	3,699,446	-0-	
8	Leased to Others						
9	Held for Future Use						
10	Construction Work in Progress	395,895,945	395,759,360	136,585	-0-	-0-	
11	Acquisition Adjustments						
12	TOTAL Utility Plant *(Enter Total of lines 7 thru 11)*	1,216,844,920	1,129,588,750	83,556,724	3,699,446	-0-	
13	(Less) Accum. Prov. for Depr., Amort., & Depl.	167,239,642	141,933,251	24,417,571	888,720	-0-	
14	Net Utility Plant Less Nuclear Fuel *(Enter Total of line 12 less 13)*	1,049,605,278	987,655,499	59,139,053	2,810,726	-0-	
15	DETAIL OF ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION						
16	In Service						
17	Depreciation	167,134,707	141,828,316	24,417,671	888,720	-0-	
18	Amort. and Depl. of Producing Natural Gas Land and Land Rights						
19	Amort. of Underground Storage Land and Land Rights						
20	Amort. of Other Utility Plant	104,935	104,935				
21	TOTAL In Service *(Enter Total of lines 17 thru 20)*	167,239,642	141,933,251	24,417,671	888,720	-0-	
22	Leased to Others						
23	Depreciation						
24	Amortization and Depletion						
25	TOTAL Leased to Others *(Enter Total of lines 23 and 24)*	-0-	-0-	-0-	-0-	-0-	
26	Held for Future Use						
27	Depreciation						
28	Amortization						
29	TOTAL Held for Future Use *(Enter Total of lines 27 and 28)*	-0-	-0-	-0-	-0-	-0-	
30	Abandonment of Leases (Natural Gas)						
31	Amort. of Plant Acquisition Adj.						
32	TOTAL Accumulated Provisions (Should agree with line 13 above) *(Enter Total of lines 21, 25, 29, 30, and 31)*	167,239,642	141,933,251	24,417,671	888,720	-0-	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
The Wasington Water Power Company	(1) [X] An Original (2) [ ] A Resubmission	April 30, 1984	Dec. 31, 19 83

NUCLEAR FUEL MATERIALS (Accounts 120.1 through 120.5 and 157)

1. Report below the costs incurred for nuclear fuel materials in process of fabrication, on hand, in reactor, and in cooling; owned by the respondent.

2. If the nuclear fuel stock is obtained under leasing arrangements, attach a statement showing the amount of nuclear fuel leased, the quantity used and quantity on hand, and the costs incurred under such leasing arrangements.

Line No.	Description of Item (a)	Balance Beginning of Year (b)	Changes During Year: Additions (c)	Changes During Year: Amortization (d)	Changes During Year: Other Reductions (Explain in a footnote) (e)	Balance End of Year (f)
1	Nuclear Fuel in Process of Refinement, Conversion, Enrichment & Fabrication (120.1)		1,925,334			1,925,334
2	Fabrication					
3	Nuclear Materials					
4	Allowance for Funds Used during Construction		1,016,450			1,016,450
5	Other Overhead Construction Costs					
6	SUBTOTAL *(Enter Total of lines 2 thru 5)*					2,941,784
7	Nuclear Fuel Materials and Assemblies					
8	In Stock (120.2)					
9	In Reactor (120.3)					
10	SUBTOTAL *(Enter Total of lines 8 and 9)*					
11	Spent Nuclear Fuel (120.4)					
12	Less Accum. Prov. for Amortization of Nuclear Fuel Assemblies (120.5)					
13	TOTAL Nuclear Fuel Stock *(Enter Total of lines 6, 10, and 11 less line 12)*					2,941,784
14	Estimated Net Salvage Value of Nuclear Materials in line 9					
15	Estimated Net Salvage Value of Nuclear Materials in line 11					
16	Estimated Net Salvage Value of Nuclear Materials in Chemical Processing					
17	Nuclear Materials Held for Sale (157)					
18	Uranium					
19	Plutonium					
20	Other					
21	TOTAL Nuclear Materials Held for Sale *(Enter Total of lines 18, 19, and 20)*					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
The Washington Water Power Company	(1) [X] An Original (2) [ ] A Resubmission	April 30, 1984	Dec. 31, 19 83

ELECTRIC PLANT IN SERVICE (Accounts 101, 102, 103, and 106)

1. Report below the original cost of electric plant in service according to the prescribed accounts.
2. In addition to Account 101, *Electric Plant in Service (Classified)*, this page and the next include Account 102, *Electric Plant Purchased or Sold;* Account 103, *Experimental Electric Plant Unclassified;* and Account 106, *Completed Construction Not Classified—Electric.*
3. Include in column (c) or (d), as appropriate, corrections of additions and retirements for the current or preceding year.
4. Enclose in parentheses credit adjustments of plant accounts to indicate the negative effect of such amounts.
5. Classify Account 106 according to prescribed accounts, on an estimated basis if necessary, and include the entries in column (c). Also to be included in column (c) are entries for reversals of tentative distributions of prior year reported in column (b). Likewise, if the respondent has a significant amount of plant retirements which have not been classified to primary accounts at

(Continued on page 204)

Line No	Account (a)	Balance at Beginning of Year (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)
1	1. INTANGIBLE PLANT						
2	(301) Organization						
3	(302) Franchises and Consents	193,079					193,079
4	(303) Miscellaneous Intangible Plant						
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	193,079					193,079
6	2. PRODUCTION PLANT						
7	A. Steam Production Plant (1)						
8	(310) Land and Land Rights	264,203	251,926				516,129
9	(311) Structures and Improvements	5,548,865	20,017,027	4,142			25,561,750
10	(312) Boiler Plant Equipment	29,727,599	40,907,797				70,635,396
11	(313) Engines and Engine Driven Generators	179					179
12	(314) Turbogenerator Units	7,633,923	13,857,641				21,491,564
13	(315) Accessory Electric Equipment	2,799,048	8,952,264				11,751,312
14	(316) Misc. Power Plant Equipment	505,660	1,888,873				2,394,533
15	TOTAL Steam Production Plant (Enter Total of lines 8 thru 14)	46,479,477	85,875,528	4,142			132,350,863
16	B. Nuclear Production Plant						
17	(320) Land and Land Rights						
18	(321) Structures and Improvements						
19	(322) Reactor Plant Equipment						
20	(323) Turbogenerator Units						
21	(324) Accessory Electric Equipment						
22	(325) Misc. Power Plant Equipment						
23	TOTAL Nuclear Production Plant (Enter Total of lines 17 thru 22)						
24	C. Hydraulic Production Plant						
25	(330) Land and Land Rights	42,015,892	318				42,016,210
26	(331) Structures and Improvements	19,628,369	37,001	50			19,665,320
27	(332) Reservoirs, Dams, and Waterways	55,267,064	1,844				55,268,908
28	(333) Water Wheels, Turbines, and Generators	42,755,318	130,129				42,885,447
29	(334) Accessory Electric Equipment	5,119,701	14,071	435			5,133,337
30	(335) Misc. Power Plant Equipment	2,265,561	31,519	706			2,296,374
31	(336) Roads, Railroads, and Bridges	911,333					911,333
32	TOTAL Hydraulic Production Plant (Enter Total of lines 25 thru 31)	167,963,238	214,882	1,191			168,176,929

Note: (1) See Note Page 450.

FERC FORM NO. 1 (REVISED 12-81)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
The Washington Water Power Company	(1) [X] An Original (2) [ ] A Resubmission	April 30, 1984	Dec. 31, 19 83

ELECTRIC PLANT IN SERVICE (Accounts 101, 102, 103, and 106) (Continued)

Line No.	Account (a)	Balance at Beginning of Year (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)
33	D. Other Production Plant						
34	(340) Land and Land Rights	143,423		2,560			140,863
35	(341) Structures and Improvements	556,945	4,534				561,479
36	(342) Fuel Holders, Products, and Accessories	1,269,026	8,541	200			1,277,367
37	(343) Prime Movers	7,728,108	174				7,728,282
38	(344) Generators	2,917,827					2,917,827
39	(345) Accessory Electric Equipment	170,165					170,165
40	(346) Misc. Power Plant Equipment	327,208					327,208
41	TOTAL Other Production Plant *(Enter Total of lines 34 thru 40)*	13,112,702	13,249	2,760			13,123,191
42	TOTAL Production Plant *(Enter Total of lines 15, 23, 32, and 41)*	227,555,417	86,103,659	8,093			313,650,983
43	3. TRANSMISSION PLANT						
44	(350) Land and Land Rights	6,286,625	1,057,809	171		3,350	7,347,613
45	(352) Structures and Improvements	1,362,400	500,327	6,020			1,856,707
46	(353) Station Equipment	42,919,400	5,749,062	445,432		(15,118)	48,207,912
47	(354) Towers and Fixtures	3,148,349	21,229				3,169,578
48	(355) Poles and Fixtures	21,247,822	2,028,018	274,311		156,983	23,158,512
49	(356) Overhead Conductors and Devices	24,096,301	2,571,057	257,114		283,902	26,694,146
50	(357) Underground Conduit	373,362					373,362
51	(358) Underground Conductors and Devices	591,484	4,093				595,577
52	(359) Roads and Trails	52,905					52,905
53	TOTAL Transmission Plant *(Enter Total of lines 44 thru 52)*	100,078,648	11,931,595	983,048		429,117	111,456,312
54	4. DISTRIBUTION PLANT						
55	(360) Land and Land Rights	2,397,654	103,402			(5,919)	2,495,137
56	(361) Structures and Improvements	3,981,577	400,630	39,331		(11,191)	4,331,685
57	(362) Station Equipment	35,966,926	1,687,630	406,954		4,037	37,251,639
58	(363) Storage Battery Equipment						
59	(364) Poles, Towers, and Fixtures	52,454,303	3,667,958	378,004		(144,555)	55,599,702
60	(365) Overhead Conductors and Devices	36,999,640	2,695,721	163,575		(272,717)	39,259,069
61	(366) Underground Conduit	5,100,052	399,681	10,830			5,488,903
62	(367) Underground Conductors and Devices	17,132,701	1,623,158	108,932			18,646,927
63	(368) Line Transformers	49,261,522	4,137,857	552,784		(4,696)	52,841,899
64	(369) Services	23,652,950	1,915,151	88,578			25,479,523
65	(370) Meters	10,049,261	1,134,504	496,701			10,687,064
66	(371) Installations on Customer Premises						

Name of Respondent	This Report Is:	Date of Report	Year of Report
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ELECTRIC PLANT IN SERVICE (Accounts 101, 102, 103, and 106) (Continued)

the end of the year, include in column (d) a tentative distribution of such retirements, on an estimated basis, with appropriate contra entry to the account for accumulated depreciation provision. Include also in column (d) reversals of tentative distributions of prior year of unclassified retirements. Attach supplemental statement showing the account distributions of these tentative classifications in columns (c) and (d), including the reversals of the prior years tentative account distributions of these amounts. Careful observance of the above instructions and the texts of Accounts 101 and 106 will avoid serious omissions of the reported amount of respondent's plant actually in service at end of year.

6. Show in column (f) reclassifications or transfers within utility plant accounts. Include also in column (f) the additions or reductions of primary account classifications arising from distribution of amounts initially recorded in Account 102. In showing the clearance of Account 102, include in column (e) the amounts with respect to accumulated provision for depreciation, acquisition adjustments, etc., and show in column (f) only the offset to the debits or credits distributed in column (f) to primary account classifications.

7. For Account 399, state the nature and use of plant included in this account and if substantial in amount submit a supplementary statement showing subaccount classification of such plant conforming to the requirements of these pages.

8. For each amount comprising the reported balance and changes in Account 102, state the property purchased or sold, name of vendor or purchaser, and date of transaction. If proposed journal entries have been filed with the Commission as required by the Uniform System of Accounts, give also date of such filing.

Line No.	Account (a)	Balance at Beginning of Year (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)
67	(372) Leased Property on Customer Premises						
68	(373) Street Lighting and Signal Systems	7,460,921	296,340	928,058			6,829,203
69	TOTAL Distribution Plant *(Enter Total of lines 55 thru 68)*	244,457,507	18,062,032	3,173,747		(435,041)	258,910,751
70	5. GENERAL PLANT						
71	(389) Land and Land Rights	1,137,394	114,554				1,251,948
72	(390) Structures and Improvements	20,926,723	547,661	2,971		(22,961)	21,448,452
73	(391) Office Furniture and Equipment	5,363,157	4,166,939	110,717		(2,397)	9,416,982
74	(392) Transportation Equipment	6,261,175	726,396	232,902		(97,459)	6,657,210
75	(393) Stores Equipment	214,074	29,092	351		351	243,166
76	(394) Tools, Shop and Garage Equipment	1,131,153	94,627	12,212		1,218	1,214,786
77	(395) Laboratory Equipment	494,322	55,825	7,306			542,841
78	(396) Power Operated Equipment	4,220,724	472,581	17,671		(35,639)	4,639,995
79	(397) Communication Equipment	3,456,364	645,705	37,999			4,064,070
80	(398) Miscellaneous Equipment	136,482	2,530	7,408		7,211	138,815
81	SUBTOTAL *(Enter Total of lines 71 thru 80)*	43,341,568	6,855,910	429,537		(149,676)	49,618,265
82	(399) Other Tangible Property						
83	TOTAL General Plant *(Enter Total of lines 81 and 82)*	43,341,568	6,855,910	429,537		(149,676)	49,618,265
84	TOTAL (Accounts 101 and 106)						
85	(102) Electric Plant Purchased *(See Inst. 8)*						
86	(Less) (102) Electric Plant Sold *(See Instr. 8)*						
87	(103) Experimental Electric Plant Unclassified						
88	TOTAL Electric Plant in Service	615,626,219	122,953,196	4,594,425		(155,600)	733,829,390

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
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CONSTRUCTION WORK IN PROGRESS—ELECTRIC (Account 107)

1. Report below descriptions and balances at end of year of projects in process of construction (107).
2. Show items relating to "research, development, and demonstration" projects last, under a caption Research, Development, and Demonstration (see Account 107 of the Uniform System of Accounts).
3. Minor projects (5% of the Balance End of the Year for Account 107 or $100,000, whichever is less) may be grouped.

Line No.	Description of Project (a)	Construction Work in Progress—Electric (Account 107) (b)
1	STATE OF WASHINGTON	
2	Preliminary Costs - Various Jobs	1,497,138
3	Liberty Lake 115 Kv Sub - Add Trfs./Fdrs.	147,279
4	Milan 115 Kv Sub - New Construction	128,434
5	Nuclear Gen. Sta. - WPPSS No. 3 (5% share)	132,843,858
6	Marshall 230 Kv Sub - New Construction	108,577
7	Addy-Orin 115 Kv Line - Construct	208,674
8	Colville Sub - Install 2nd Tfr./4th Fdrs.	145,801
9	Beacon 230 Kv Sub - Reconstruction	3,297,935
10	Columbia Basin Project	281,850
11	Supervisory Control & Data Acquisition (SCADA)	1,921,180
12	Kettle Falls Wood Waste Plant - Fuel Handling/Processing	383,478
13	Centralia Plant (15% share)	121,348
14	Minor Projects (53) under $100,000	1,085,438
15		142,170,990
16		
17	STATE OF IDAHO	
18	Supervisory Control & Data Acquisition (SCADA)	108,617
19	Pine Cr. - Thompson Falls 230 Kv Ln. (Pine Cr. - Taft Portion)	220,767
20	Idaho Electric Heat Contributions	(168,296)
21	Grangeville 115 Kv Sub - Add 2nd Autotransformer	261,208
22	Rathdrum 230 Kv Sub - Install 2nd Autotransformer	558,452
23	CDAlene Overflow - Post Falls Hydro Project	129,222
24	Construct New Bunkhouse - Clark Fork	340,323
25	Bovill 24 Kv Elk River Fdr. - Rebuild	155,079
26	Sweetwater 115 Kv Sub - New Construction	158,315
27	Benewah 230 Kv Sub - Install 230 Kv OCB/Aux. Bus.	230,259
28	Benewah 230 Kv Sub - Install 230/115 Kv Trf.	599,303
29	Dalton 115 Kv Sub - Constr. Ln./2nd Trf./4th Fdr.	158,780
30	Minor Project (35) under $100,000	494,036
31		3,246,065
32		
33	STATE OF MONTANA	
34	Colstrip Gen. #3 & 4 - (15% share)	249,566,267
35	Rewind Unit #3 Noxon	621,707
36	Minor Projects (5) under $100,000	154,331
37		250,342,305
38		
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45		
46	TOTAL	395,759,360

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CONSTRUCTION OVERHEADS–ELECTRIC

1. List in column (a) the kinds of overheads according to the titles used by the respondent. Charges for outside professional services for engineering fees and management or supervision fees capitalized should be shown as separate items.
2. On page 212 furnish information concerning construction overheads.
3. A respondent should not report "none" to this page if no overhead apportionments are made, but rather should explain on page 212 the accounting procedures employed and the amounts of engineering, supervision and administrative costs, etc., which are directly charged to construction.
4. Enter on this page engineering, supervision, administrative, and allowance for funds used during construction, etc., which are first assigned to a blanket work order and then prorated to construction jobs.

Line No.	Description of Overhead (a)	Total Amount Charged for the Year (b)
1	General Engineering and Accounting Expense	2,552,339
2		
3	Construction Engineering and Supervision	1,174,088
4		
5	Engineering and Superintendence	907,508
6		
7	Allowance for Funds Used During Construction	33,079,502
8		
9		
10		
11		
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46	TOTAL	37,713,437

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GENERAL DESCRIPTION OF CONSTRUCTION OVERHEAD PROCEDURE

1. For each construction overhead explain: (a) the nature and extent of work, etc., the overhead charges are intended to cover, (b) the general procedure for determining the amount capitalized, (c) the method of distribution to construction jobs, (d) whether different rates are applied to different types of construction, (e) basis of differentiation in rates for different types of construction, and (f) whether the overhead is directly or indirectly assigned.

2. Show below the computation of allowance for funds used during construction rates, in accordance with the provisions of Electric Plant Instructions 3 (17) of the U.S. of A.

3. Where a net-of-tax rate for borrowed funds is used, show the appropriate tax effect adjustment to the computations below in a manner that clearly indicates the amount of reduction in the gross rate for tax effects.

A_b = Gross allowance for borrowed funds used during construction rate

$$= .0938\left(\frac{48{,}529{,}433}{388{,}258{,}400}\right) + .0915\left(\frac{415{,}438{,}000}{909{,}936{,}155}\right)\left(1 - \frac{48{,}529{,}433}{388{,}258{,}400}\right)$$

= 4.83%

A_o = Allowance for other funds used during construction rate

$$\left(1 - \frac{48{,}529{,}433}{388{,}258{,}400}\right)\left(.1261\left(\frac{93{,}761{,}263}{909{,}936{,}155}\right) + .1625\left(\frac{400{,}736{,}892}{909{,}936{,}155}\right)\right)$$

= 7.40%

COMPUTATION OF ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION RATES

For line 1(5), column (d) below, enter the rate granted in the last rate proceeding. If such is not available, use the average rate actually earned during the preceding three years.

1. Components of Formula (Derived from actual book balances and actual cost rates):

Line No.	Title (a)	Amount (b)	Capitalization Ratio (Percent) (c)	Cost Rate Percentage (d)
(1)	Average Short Term Debt	S 48,529,433		
(2)	Short-Term Interest			s 9.38%
(3)	Long-Term Debt	D 415,438,000	45.66%	d 9.15%
(4)	Preferred Stock	P 93,761,263	10.30%	p 12.61%
(5)	Common Equity	C 400,736,892	44.04%	c 16.25%
(6)	Total Capitalization	909,936,155	100%	
(7)	Average Construction Work in Progress Balance	W 388,258,400		

2. Gross Rate for Borrowed Funds $s\left(\frac{S}{W}\right) + d\left(\frac{D}{D+P+C}\right)\left(1 - \frac{S}{W}\right)$ 4.83%

3. Rate for Other Funds $\left[1 - \frac{S}{W}\right]\left[p\left(\frac{P}{D+P+C}\right) + c\left(\frac{C}{D+P+C}\right)\right]$ 7.40%

4. Weighted Average Rate Actually Used for the Year:
   a. Rate for Borrowed Funds— 4.83%
   b. Rate for Other Funds— 7.37%

General Engineering and Accounting Expense

Represents wages, salaries and expenses of those employees devoting all or a portion of their time to general engineering and accounting work of a capital nature. Monthly charges are accumulated in a specific work order in construction work in progress and allocated to completed jobs at the time of transfer to utility plant in service. Allocation is based on a predetermined annual percentage applied to the appropriate capital accounts for all types of construction, exclusive of certain types of general equipment.

Construction Engineering and Supervision

Represents engineering and supervisory labor and expenses performed on minor blanket construction authorizations. Monthly charges are accumulated in a specific work order in construction work in progress and allocated to completed jobs at the time of transfer to utility plant in service. Allocation is based on a predetermined annual percentage applied to the appropriate capital accounts for all construction performed under the blanket authorizations.

Engineering and Superintendence (Direct)

Where construction jobs are of significant size or complexity to warrant specific authorization, engineering and superintendence costs relating thereto are charged direct. Upon completion of the job, the total charges are allocated to the appropriate plant accounts on a dollar basis.

Allowance for Funds Used During Construction (AFUDC)

AFUDC is computed on new construction costs during the construction period and compounded semi-annually. The rate is 1/12th of 12.2% on the accumulated balance at the beginning of the month and at 1/12th of 6.1% on the current month's costs. Certain types of general equipment are excluded. The Company's rates do not exceed the maximum allowable rates as determined in compliance with a formula prescribed by FERC.

Other Miscellaneous Overheads Capitalized

The Company also capitalizes certain payroll taxes, employee benefit costs, and small tools which, upon completion of the job, are charged to the job on predetermined percentages applied to labor costs. Certain types of general equipment are excluded.

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ACCUMULATED PROVISION FOR DEPRECIATION OF ELECTRIC UTILITY PLANT (Account 108)

1. Explain in a footnote any important adjustments during year.
2. Explain in a footnote any difference between the amount for book cost of plant retired, line 11, column (c), and that reported for electric plant in service, pages 202-204, column (d), excluding retirements of non-depreciable property.
3. The provisions of Account 108 in the Uniform System of Accounts require that retirements of depreciable plant be recorded when such plant is removed from service. If the respondent has a significant amount of plant retired at year end which has not been recorded and/or classified to the various reserve functional classifications, make preliminary closing entries to tentatively functionalize the book cost of the plant retired. In addition, include all costs included in retirement work in progress at year end in the appropriate functional classifications.
4. Show separately interest credits under a sinking fund or similar method of depreciation accounting.

Section A. Balances and Changes During Year

Line No.	Item (a)	Total (c + d + e) (b)	Electric Plant in Service (c)	Electric Plant Held for Future Use (d)	Electric Plant Leased to Others (e)
1	Balance Beginning of Year	131,521,897	131,521,897		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	13,748,267	13,748,267		
4	(413) Expenses of Electric Plant Leased to Others				
5	Transportation Expenses—Clearing	625,117	625,117		
6	Other Clearing Accounts				
7	Other Accounts *(Specify)* (403) Gas Dept.	439,425	439,425		
8					
9	TOTAL Depreciation Provisions for Year *(Enter Total of lines 3 thru 8)*	14,812,809	14,812,809		
10	Net Charges for Plant Retired				
11	Book Cost of Plant Retired	4,594,425	4,594,425		
12	Cost of Removal	1,195,667	1,195,667		
13	Salvage (Credit)	1,361,960	1,361,960		
14	TOTAL Net Charges for Plant Retired *(Enter Total of lines 11 thru 13)*	4,428,132	4,428,132		
15	Other Debit or Credit Items *(Describe)* Transfer from Gas Dept.	2,546	2,546		
16	Accum. Depr. Appl. to Sale of Equip. with Water Systems	(80,804)	(80,804)		
17	Balance End of Year *(Enter Total of lines 1, 9, 14, 15, and 16)*	141,828,316	141,828,316		

Section B. Balances at End of Year According to Functional Classifications

Line No.	Item (a)	Total (c + d + e) (b)	Electric Plant in Service (c)	Electric Plant Held for Future Use (d)	Electric Plant Leased to Others (e)
18	Steam Production	14,758,596	14,758,596		
19	Nuclear Production				
20	Hydraulic Production—Conventional	21,829,684	21,829,684		
21	Hydraulic Production—Pumped Storage				
22	Other Production	2,984,614	2,984,614		
23	Transmission	25,452,430	25,452,430		
24	Distribution	64,123,130	64,123,130		
25	General	12,679,862	12,679,862		
26	TOTAL *(Enter Total of lines 18 thru 25)*	141,828,316	141,828,316		

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NONUTILITY PROPERTY (Account 121)

1. Give a brief description and state the location of nonutility property included in Account 121.
2. Designate with an asterisk any property which is leased to another company. State name of lessee and whether lessee is an associated company.
3. Furnish particulars (details) concerning sales, purchases, or transfers of Nonutility Property during the year.
4. List seperately all property previously devoted to public service and give date of transfer to Account 121, *Nonutility Property*.
5. Minor Items (5% of the Balance at the End of the Year for Account 121 or $100,000, whichever is less) may be grouped by (1) previously devoted to public service (line 43), or (2) other nonutility property (line 44).

Line No.	Description and Location (a)	Balance at Beginning of Year (b)	Purchases, Sales, Transfers, etc. (c)	Balance at End of Year (d)
1	State of Washington			
2	Spokane River Project (1)	209,316	(35,293)	174,023
3	Opportunity Project (2)	112,228		112,228
4	Skagit County Property (3)	501,181	(2,736)	498,445
5	Clarkston New Office Site (4)	82,919		82,919
6	Total State of Washington	905,644	(38,029)	867,615
7				
8	State of Idaho			
9	3612 Fairway Dr., Coeur d'Alene, ID		105,000	105,000
10	3011 Fernan Court, Coeur d'Alene, ID		100,000	100,000
11	3604 Hillcrest Dr., Coeur d'Alene, ID		92,500	92,500
12	Total State of Idaho		297,500	297,500
13				
14				
15				
16				
17				
18				
19				
20				
21	Notes: (1) Previously devoted to public service; transferred to Account 121, April 1979.			
22				
23	(2) Previously devoted to public service; transferred to Account 121, December 1981.			
24				
25	(3) Transferred to Account 121, April 1982.			
26				
27	(4) Previously devoted to public service; transferred to Account 121, August 1982.			
28				
29				
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39				
40				
41				
42				
43	Minor Item Previously Devoted to Public Service 40 Items	75,437	75,467	150,904
44	Minor Items – Other Nonutility Property 6 Items	17,756	49,852	67,608
45	TOTAL	998,837	[illegible]	1,383,627

FERC FORM NO. 1 (REVISED 12-81)

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
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INVESTMENT IN SUBSIDIARY COMPANIES (Account 123.1)

1. Report below investments in Account 123.1, *Investment in Subsidiary Companies*.

2. Provide a subheading for each company and list thereunder the information called for below. Sub-total by company and give a total in columns (e), (f), (g) and (h).

(a) Investment in Securities — List and describe each security owned. For bonds give also principal amount, date of issue, maturity, and interest rate.

(b) Investment Advances — Report separately the amounts of loans or investment advances which are subject to repayment, but which are not subject to current settlement. With respect to each advance show whether the advance is a note or open account. List each note giving date of issuance, maturity date, and specifying whether note is a renewal.

3. Report separately the equity in undistributed subsidiary earnings since acquisition. The total in column (e) should equal the amount entered for Account 418.1.

4. For any securities, notes, or accounts that were pledged, designate such securities, notes, or accounts in a footnote, and state the name of pledgee and purpose of the pledge.

5. If Commission approval was required for any advance made or security acquired, designate such fact in a footnote and give name of Commission, date of authorization, and case or docket number.

6. Report column (f) interest and dividend revenues from investments, including such revenues from securities disposed of during the year.

7. In column (h), report for each investment disposed of during the year, the gain or loss represented by the difference between cost of the investment (or the other amount at which carried in the books of account if different from cost) and the selling price thereof, not including interest adjustment includible in column (f).

8. Report on line 23, column (a) the total cost of Account 123.1.

Line No.	Description of Investment (a)	Date Acquired (b)	Date of Maturity (c)	Amount of Investment at Beginning of Year (d)	Equity in Subsidiary Earnings for Year (e)	Revenues for Year (f)	Amount of Investment at End of Year (g)	Gain or Loss from Investment Disposed of (h)
1	Wash. Irrig. & Dev. Co.-Common Stock	Var.		14,200,000			14,200,000	
2	Wash. Irrig. & Dev. Co.-Equity in Earn.			11,125,037	5,062,605	(4,835,100)	11,352,542	
3	Total			25,325,037	5,062,605	(4,835,100)(1)	25,552,542	
4								
5	Spokane Ind. Park, Inc.-Common Stock	Var.		855,898			855,898	
6	Spokane Ind. Park, Inc.-Equity in Earn.			6,861,918	1,304,307		8,166,225	
7	Total			7,717,816	1,304,307		9,022,123	
8								
9	Development Assoc. Inc.-Common Stock	1961		300,001			300,001	
10	Development Assoc. Inc.-Advance	Var.		182,275		(100,000)	82,275	
11	Development Assoc. Inc.-Equity in Earn.			113,477	47,199		160,676	
12	Total			595,753	47,199	(100,000)(2)	542,952	
13								
14	The Limestone Co., Inc.-Common Stock	1970		35,715			35,715	
15	The Limestone Co., Inc.-Equity in Earn.			53,005	371		53,376	
16	Total			88,720	371		89,091	
17								
18	Water Power Impr. Co.-Common Stock	Var.		1,445,000			1,445,000	
19	Water Power Impr. Co.-Note Receivable	Var.				1,321,215	1,321,215	
20	Water Power Impr. Co.-Equity in Earn.			(1,961,648)	(381,267)		(2,342,915)	
21	Total			(516,648)	(381,267)	1,321,215(3)	423,300	
22								
23								

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INVESTMENT IN SUBSIDIARY COMPANIES (Account 123.1)

1. Report below investments in Account 123.1, *Investment in Subsidiary Companies.*

2. Provide a subheading for each company and list thereunder the information called for below. Sub-total by company and give a total in columns (e), (f), (g) and (h).

(a) Investment in Securities — List and describe each security owned. For bonds give also principal amount, date of issue, maturity, and interest rate.

(b) Investment Advances — Report separately the amounts of loans or investment advances which are subject to repayment, but which are not subject to current settlement. With respect to each advance show whether the advance is a note or open account. List each note giving date of issuance, maturity date, and specifying whether note is a renewal.

3. Report separately the equity in undistributed subsidiary earnings since acquisition. The total in column (e) should equal the amount entered for Account 418.1.

4. For any securities, notes, or accounts that were pledged, designate such securities, notes, or accounts in a footnote, and state the name of pledgee and purpose of the pledge.

5. If Commission approval was required for any advance made or security acquired, designate such fact in a footnote and give name of Commission, date of authorization, and case or docket number.

6. Report column (f) interest and dividend revenues from investments, including such revenues from securities disposed of during the year.

7. In column (h), report for each investment disposed of during the year, the gain or loss represented by the difference between cost of the investment (or the other amount at which carried in the books of account if different from cost) and the selling price thereof, not including interest adjustment includible in column (f).

8. Report on line 23, column (a) the total cost of Account 123.1.

Line No.	Description of Investment (a)	Date Acquired (b)	Date of Maturity (c)	Amount of Investment at Beginning of Year (d)	Equity in Subsidiary Earnings for Year (e)	Revenues for Year (f)	Amount of Investment at End of Year (g)	Gain or Loss from Investment Disposed of (h)
24	WP Energy Co.-Common Stock	1981		25,000		(25,000)		
25	WP Energy Co.- Equity in Earn.			5,878	124,232	(130,110)		
26	Total			30,878	124,232	(155,110)(4)		
27								
28	N.W. Energy Services-Common Stock	1981		250,000			250,000	
29	N.W. Energy Services-Equity in Earn.			(26,099)	(39,425)		(65,524)	
30	Total			223,901	(39,425)		184,476	
31								
32	Empire Energy Co.-Common Stock	1982		25,000			25,000	
33	Empire Energy Co.-Equity in Earn.				(13,271)		(13,271)	
34	Total			25,000	(13,271)		11,729	
35								
36								
37	Adjustment for consolidated subsidiary			(36,958)		36,958(4)		
38								
39	(1) Dividends paid by subsidiary.							
40								
41	(2) Annual repayment of subsidiary advance.							
42								
43	(3) Long-term note receivable classified as investment in subsidiary.							
44								
45	(4) Merger of WP Energy Co. with The Washington Water Power Company							
46	Total Cost of Account 123.1: $ 35,826,213		TOTAL	33,453,839	6,104,751	(3,732,037)	35,826,213	

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MATERIALS AND SUPPLIES

1. For Account 154, report the amount of plant materials and operating supplies under the primary functional classifications as indicated in column (a); estimates of amounts by function are acceptable. In column (d), designate the department or departments which use the class of material.

2. Give an explanation of important inventory adjustments during year (on a supplemental page) showing general classes of material and supplies and the various accounts (operating expense, clearing accounts, plant, etc.) affected—debited or credited. Show separately debits or credits to stores expense-clearing, if applicable.

Line No.	Account (a)	Balance Beginning of Year (b)	Balance End of Year (c)	Department or Departments Which Use Material (d)
1	Fuel Stock (Account 151)	6,929,088	7,410,744	(1), (3)
2	Fuel Stock Expenses Undistributed (Account 152)			
3	Residuals and Extracted Products (Account 153)			
4	Plant Materials and Operating Supplies (Account 154)			
5	Assigned to — Construction (Estimated)	5,418,252	6,250,307	(1)
6	Assigned to — Operations and Maintenance			
7	Production Plant (Estimated)	6,352	5,199	(1)
8	Transmission Plant (Estimated)	12,704	8,087	(1)
9	Distribution Plant (Estimated)	114,336	90,689	(1)
10	Assigned to — Other	800,351	280,732	(1), (2), (3)
11	TOTAL Account 154 *(Enter Total of lines 5 thru 10)*	6,351,995	6,635,014	
12	Merchandise (Account 155)			
13	Other Materials and Supplies (Account 156)			
14	Nuclear Materials Held for Sale (Account 157) (Not applicable to Gas Utilities)			
15	Stores Expense Undistributed (Account 163)	32,964	(9,447)	
16				
17				
18				
19				
20	TOTAL Materials and Supplies (Per Balance Sheet)	13,314,047	14,036,312	

Note: (1) Electric
(2) Gas
(3) Steam Heat

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
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MISCELLANEOUS DEFERRED DEBITS (Account 186)

1. Report below the particulars (details) called for concerning miscellaneous deferred debits.
2. For any deferred debit being amortized, show period of amortization in column (a).
3. Minor items (1% of the Balance at End of Year for Account 186 or amounts less than $50,000, whichever is less) may be grouped by classes.

Line No.	Description of Miscellaneous Deferred Debit (a)	Balance at Beginning of Year (b)	Debits (c)	CREDITS Account Charged (d)	CREDITS Amount (e)	Balance at End of Year (f)
1	Miscellaneous Undistributed					
2	Charges (9 items)	37,465	2,283,765	Various	2,176,768	144,462
3						
4	Water Heater Insulation					
5	Blankets - WA (3 years)	73,537	136,021	908 & 143.2	209,558	
6						
7	Water Heater Insulation					
8	Blankets - ID (6 years)	27,013	61,226	908 & 143.2	88,239	
9						
10	Company Home Sale Plan for					
11	Managers' Relocation (13 items)	728,751	148,825	Various	601,051	276,525
12						
13	Residential Purchase and Sale					
14	Agreement-Bonneville Power					
15	Administration	20,034	30,610			50,644
16						
17	Southern California Edison Co.	1,254,094		186.31	172,526	1,081,568
18						
19	Weatherization Grants (6-9 years)	1,882,906	11,126,482	908	1,511,917	11,497,471
20						
21	Undelivered Coal-WIDCo	1,197,424	1,075,124	186.6	1,344,102	928,446
22						
23	Street Light Change					
24	Washington	121,364	994,678	107	1,512,035	(395,993)
25						
26	Street Light Change					
27	Idaho	52,142	183,104	107	353,779	(118,533)
28						
29	Return of Ratepayer Contribution					
30	in Excess of Refund - Gas					
31	Exploration Advance		147,874	1798	29,750	118,124
32						
33	Investment in Terminated Nuclear					
34	Project (Skagit)		39,339,840			39,339,840
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47	Misc. Work in Progress	661,715				621,954
48	DEFERRED REGULATORY COMMISSION EXPENSES *(See pages 350-351)*		902,379	Various	902,355	24
49	TOTAL	6,056,445				53,544,532

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
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CAPITAL STOCK (Accounts 201 and 204)

1. Report below the particulars (details) called for concerning common and preferred stock at end of year, distinguishing separate series of any general class. Show separate totals for common and preferred stock. If information to meet the stock exchange reporting requirement outlined in column (a) is available from the SEC 10-K Report Form filing, a specific reference to the report form (i.e. year and company title) may be reported in column (a) provided the fiscal years for both the 10-K report and this report are compatible.

2. Entries in column (b) should represent the number of shares authorized by the articles of incorporation as amended to end of year.

3. Give particulars (details) concerning shares of any class and series of stock authorized to be issued by a regulatory commission which have not yet been issued.

4. The identification of each class of preferred stock should show the dividend rate and whether the dividends are cumulative or noncumulative.

5. State in a footnote if any capital stock which has been nominally issued is nominally outstanding at end of year.

6. Give particulars (details) in column (a) of any nominally issued capital stock, reacquired stock, or stock in sinking and other funds which is pledged, stating name of pledgee and purpose of pledge.

Line No.	Class and Series of Stock and Name of Stock Exchange (a)	Number of Shares Authorized by Charter (b)	Par or Stated Value Per Share (c)	Call Price at End of Year (d)	Outstanding per Balance Sheet (Total amount outstanding without reduction for amounts held by respondent) Shares (e)	Outstanding per Balance Sheet Amount (f)	Held by Respondent: As Reacquired Stock (Account 217) Shares (g)	Held by Respondent: As Reacquired Stock Cost (h)	Held by Respondent: In Sinking and Other Funds Shares (i)	Held by Respondent: In Sinking and Other Funds Amount (j)
1	Acct. 201 - Common Capital Stock									
2		40,000,000								
3	No Par Value				20,130,830	362,031,658	None		None	
4	Book Value Dec. 31, 1983:									
5	$22.68									
6	Listed:									
7	New York Stock Exchange									
8	Pacific Stock Exchange									
9	Spokane Stock Exchange									
10										
11	Acct. 204 - Preferred Stock									
12		10,000,000								
13	No Par $9.00 Series A		100	105	250,000	25,000,000	None		None	
14	Cumulative									
15	No Par $12.96 Series B		100	113	300,000	30,000,000	None		None	
16	Cumulative									
17	No Par $12.875 Series C		100	N/A	150,000	15,000,000	None		None	
18	Cumulative									
19	No Par $15.00 Series D		100	N/A	250,000	25,000,000	None		None	
20	Cumulative									
21										
22										
23										
24										
25										
26										
27										

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CAPITAL STOCK SUBSCRIBED, CAPITAL STOCK LIABILITY FOR CONVERSION, PREMIUM ON CAPITAL STOCK, AND INSTALLMENTS RECEIVED ON CAPITAL STOCK (Accounts 202 and 205, 203 and 206, 207, 212)

1. Show for each of the above accounts the amounts applying to each class and series of capital stock.
2. For Account 202, *Common Stock Subscribed*, and Account 205, *Preferred Stock Subscribed*, show the subscription price and the balance due on each class at the end of year.
3. Describe in a footnote the agreement and transactions under which a conversion liability existed under Account 203, *Common Stock Liability for Conversion*, or Account 206, *Preferred Stock Liability for Conversion* at the end of the year.
4. For Premium on Account 207, *Capital Stock*, designate with an asterisk any amounts representing the excess of consideration received over stated values of stocks without par value.

Line No.	Name of Account and Description of Item (a)	Number of Shares (b)	Amount (c)
1	Acct. 202 - Common Stock Subscribed		
2	None		
3			
4	Acct. 203 - Common Stock Liability for Conversion		
5	None		
6			
7	Acct. 205 - Preferred Stock Subscribed		
8	None		
9			
10	Acct. 206 - Preferred Stock Liability for Conversion		
11	None		
12			
13	Acct. 207 - Premium on Capital Stock		
14	None		
15			
16	Acct. 212 - Installments Received on Capital Stock		
17	Common - no par		49,805
18			
19			
20			
21			
22			
23			
24			
25			
26			
27			
28			
29			
30			
31			
32			
33			
34			
35			
36			
37			
38			
39			
40			
41			
42			
43			
44			
45			
46	TOTAL		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
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DISCOUNT ON CAPITAL STOCK (Account 213)

1. Report the balance at end of year of discount on capital stock for each class and series of capital stock.
2. If any change occurred during the year in the balance with respect to any class or series of stock, attach a statement giving particulars (details) of the change. State the reason for any charge-off during the year and specify the amount charged.

Line No.	Class and Series of Stock (a)	Balance at End of Year (b)
1	None	
2		
3		
4		
5		
6		
7		
8		
9		
10		
11		
12		
13		
14		
15		
16		
17		
18		
19		
20		
21	TOTAL	

CAPITAL STOCK EXPENSE (Account 214)

1. Report the balance at end of year of capital stock expenses for each class and series of capital stock.
2. If any change occurred during the year in the balance with respect to any class or series of stock, attach a statement giving particulars (details) of the change. State the reason for any charge-off of capital stock expense and specify the account charged.

Line No.	Class and Series of Stock (a)		Balance at End of Year (b)
1	$9.00 Preferred Stock, Series A		441,156
2	$12.96 Preferred Stock, Series B		516,714
3	$12.875 Preferred Stock, Series C		113,652
4	$15.00 Preferred Stock, Series D		157,318
5	Common Stock, no par value:		
6	Public Offering of 1,100,000 shares in April 1981	132,957	
7	Public Offering of 1,300,000 shares in October 1981	139,862	
8	Public Offering of 1,500,000 shares in March 1982	135,424	
9	Public Offering of 2,000,000 shares in October 1982	150,499	
10	Public Offering of 1,500,000 shares in September 1983	90,650	
11	Shares issued under provisions of Respondent's		
12	Dividend Reinvestment and Stock Purchase Plan	111,996	
13	Shares issued under provisions of Respondent's		
14	Employee Stock Purchase Plan	15,972	
15			777,360
16			
17			
18			
19			
20			
21			
22	TOTAL		2,016,200

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
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LONG TERM DEBT (Accounts 221, 222, 223, and 224)

1. Report by balance sheet the account particulars (details) concerning long-term debt included in Accounts 221, *Bonds*, 222, *Reacquired Bonds*, 223, *Advances from Associated Companies*, and 224, *Other Long-Term Debt*.
2. In column (a), for new issues, give Commission authorization numbers and dates.
3. For bonds assumed by the respondent, include in column (a) the name of the issuing company as well as a description of the bonds.
4. For advances from Associated Companies, report separately advances on notes and advances on open accounts. Designate demand notes as such. Include in column (a) names of associated companies from which advances were received.
5. For receivers' certificates, show in column (a) the name of the court and date of court order under which such certificates were issued.
6. In column (b) show the principal amount of bonds or other long-term debt originally issued.
7. In column (c) show the expense, premium or discount with respect to the amount of bonds or other long-term debt originally issued.
8. For column (c) the total expenses should be listed first for each issuance, then the amount of premium (in parentheses) or discount. Indicate the premium or discount with a notation, such as (P) or (D). The expenses, premium or discount should not be netted.
9. Furnish in a footnote particulars (details) regarding the treatment of unamortized debt expense, premium or discount associated with issues redeemed during the year. Also, give in a footnote the date of the Commission's authorization of treatment other than as specified by the Uniform System of Accounts.
10. Identify separately undisposed amounts applicable to issues which were redeemed in prior years.
11. Explain any debits and credits other than amortization debited to Account 428, *Amortization of Debt Discount and Expense*, or credited to Account 429, *Amortization of Premium on Debt — Credit*.
12. In a supplemental statement, give explanatory particulars (details) for Accounts 223 and 224 of net changes during the year. With respect to long-term advances, show for each company: (a) principal advanced during year, (b) interest added to principal amount, and (c) principal repaid during year. Give Commission authorization numbers and dates.
13. If the respondent has pledged any of its long-term debt securities give particulars (details) in a footnote including name of the pledgee and purpose of the pledge.
14. *If the respondent has any long-term debt securities* which have been nominally issued and are nominally outstanding at end of year, describe such securities in a footnote.
15. If interest expense was incurred during the year on any obligations retired or reacquired before end of year, include such interest expense in column (i). Explain in a footnote any difference between the total of column (i) and the total of Account 427, *Interest on Long-Term Debt* and Account 430, *Interest on Debt to Associated Companies*.
16. Give particulars (details) concerning any long-term *debt authorized by a regulatory commission but not yet* issued.

Line No.	Class and Series of Obligation, Coupon Rate *(For new issue, give Commission Authorization numbers and dates)* (a)	Principal Amount of Debt Issued (b)	Total Expense, Premium or Discount (c)	Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)
1	Acct. 221 - Bonds								
2	4 7/8% Series due 1987	30,000,000	398,617 (e)	7- 1-57	7- 1-87	7- 1-57	7- 1-87	30,000,000	1,462,500
3	4 1/8% Series due 1988	20,000,000	235,113 (e)	1- 1-58	1- 1-88	1- 1-58	1- 1-88	20,000,000	825,000
4			(86,000)(p)						
5	4 3/8% Series due 1988	15,000,000	214,201 (e)	8- 1-58	8- 1-88	8- 1-58	8- 1-88	15,000,000	656,250
6			(62,000)(p)						
7	4 3/4% Series due 1989	15,000,000	220,073 (e)	1- 1-59	2- 1-89	1- 1-59	2- 1-89	15,000,000	712,500
8	4 5/8% Series due 1994	30,000,000	338,872 (e)	4- 1-64	9- 1-94	4- 1-64	9- 1-94	30,000,000	1,387,500
9	4 5/8% Series due 1995	10,000,000	88,597 (e)	3- 1-65	3- 1-95	3- 1-65	3- 1-95	10,000,000	462,500
10	6 % Series due 1996	20,000,000	104,992 (e)	8- 1-66	8- 1-96	8- 1-66	8- 1-96	20,000,000	1,200,000
11	9 1/4% Series due 2000	20,000,000	284,124 (e)	6- 1-70	6- 1-00	6- 1-70	6- 1-00	20,000,000	1,850,000
12	7 7/8% Series due 2003	20,000,000	260,577 (e)	5- 1-73	5- 1-03	5- 1-73	5- 1-03	20,000,000	1,575,000
13			(300,000)(p)						
14	9 3/8% Series due 2005	25,000,000	334,823 (e)	2- 1-75	2- 1-05	2- 1-75	2- 1-05	25,000,000	2,343,750
15			(312,500)(p)						
16									

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LONG-TERM DEBT (Accounts 221, 222, 223, and 224) (Continued)

Line No.	Class and Series of Obligation, Coupon Rate and Commission Authorization (new issue) (a)	Principal Amount of Debt Issued (b)	Total Expense, Premium or Discount (c)	Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	AMORTIZATION PERIOD Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)
17	Acct. 221 - Bonds (contd.)								
18	8 3/4% Series due 2006	30,000,000	401,102 (e)	11- 1-76	11- 1-06	11- 1-76	11- 1-06	30,000,000	2,625,000
19	13 1/2% Series due 2013 WA FR-83-125	60,000,000	777,471 (e)	9-22-83	9- 1-13	9-22-83	9- 1-13	60,000,000	2,227,500
20	8/31/83 & 9/14/83, ID U-1008-197,		433,200 (d)						
21	Order 18281, 8/25/83								
22	14 1/8% Series due 1991	40,000,000	509,740 (e)	1- 1-81	1- 1-91	1- 1-81	1- 1-91	40,000,000	5,650,000
23	15 3/4% Series due 1990-1992	60,000,000	422,419 (e)	8-26-82	8-26-90/92	8-26-82	8-26-92	60,000,000	9,450,000
24	Subtotal	395,000,000	4,263,421					395,000,000	32,427,500
25	Sinking Fund Debentures:								
26	4 3/4% due March 1990	4,200,000	58,689 (e)	2- 1-65	3- 1-90	2- 1-65	3- 1-90	3,900,000	186,438
27	8 3/8% due June 1991	12,268,000	247,056 (e)	4- 1-71	6- 1-91	4- 1-71	6- 1-91	11,235,000	955,059
28			(75,000)(p)						
29	Subtotal	16,468,000	230,745					15,135,000	1,141,497
30	Total Acct. 221	411,468,000	4,494,166					410,135,000	33,568,997
31	Acct. 222 - Reacquired Bonds								
32	Acct. 223 - Advances from Associated Companies								
33	Acct. 224 - Other Long-Term Debt								
34	Notes Payable - Banks:								
35	Seattle-First National Bank	Various		Various	3-31-85				(2,085)
36	Rainier National Bank	"		"	"				1,024
37	Idaho First National Bank	"		"	"				16,534
38	First Interstate Bank of Washington	"		"	"				(708)
39	First Security Bank of Idaho	"		"	"				9,394
40	Idaho Bank & Trust Co.	"		"	"				5,181
41	Old National Bank of Washington	"		"	"				(367)
42	First Interstate Bank of Idaho	"		"	"				4,338
43	Washington Trust Bank	"		"	"				1,124
44	Intermediate Credit Agreement:								
45	Security Pacific National Bank	Various		Various	12-31-87				135,000
46	Bank of America	"		"	"				101,250
47	First Interstate Bank of California	"		"	"				101,250
48									
49	TOTAL								

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LONG-TERM DEBT (Accounts 221, 222, 223, and 224) (Continued)

Line No.	Class and Series of Obligation, Coupon Rate and Commission Authorization (new issue) (a)	Principal Amount of Debt Issued (b)	Total Expense, Premium or Discount (c)	Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)
17	Acct. 224 - Other Long-Term Debt (contd.)								
18	Pollution Control Revenue Bonds (1)	58,400,000	935,419 (e)	12- 1-83	12- 1-13	12- 1-83	12- 1-13	58,400,000	5,529,350
19	Less funds on deposit with Trustee	(4,173,226)						(4,173,226)	
20	Net Poll. Cont. Rev. Bonds	54,226,774						54,226,774	
21	Kettle Falls Project Financing	50,000,000		Various	Various			50,000,000	6,672,636
22	Promissory Notes:								
23	Carl T. Debord	109,544		10-10-78	9- 1-88			77,792	3,323
24	Phyllis Banker	34,402		7- 1-78	7- 5-85			17,201	1,010
25	Faye Rambo	34,402		7- 1-78	7- 5-87			22,935	1,348
26	Mortgages	83,326		Various	Various			83,326	
27	Capital Lease Obligations	2,228,992		"	"			2,033,093	128,395
28	Fixed Rate Borrowing	Various		"	"			1,000,000	723,849
29	Commercial Paper	"		"	"			50,000,000	3,752,797
30	Total Acct. 224	106,717,440	935,419					157,461,121	17,184,643
31									
32									
33									
34									
35									
36	Note: (1) On December 1, 1983, $58,400,000 in principal amount of Annual Tender Pollution Control Revenue Bonds due December 1, 2013 was								
37	issued by the City of Forsyth, Montana, and invested in U. S. Treasury Securities which were placed in a Trust for refunding the								
38	$60,000,000 principal amount of Pollution Control Revenue Bonds maturing June 1, 1984. For financial reporting purposes, the								
39	entire amount of debt ($60,000,000) is considered extinguished. The unamortized expenses associated with the extinguished debt								
40	were transferred to Account 189 in accordance with general instruction 17. The balance will be amortized over the life of the								
41	new issue.								
42									
43									
44									
45									
46									
47									
48									
49	TOTAL	518,185,440	5,429,585					567,596,121	50,753,640

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TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR

1. Give particulars (details) of the combined prepaid and accrued tax accounts and show the total taxes charged to operations and other accounts during the year. Do not include gasoline and other sales taxes which have been charged to the accounts to which the taxed material was charged. If the actual or estimated amounts of such taxes are known, show the amounts in a footnote and designate whether estimated or actual amounts.

2. Include on this page, taxes paid during the year and charged direct to final accounts, (not charged to prepaid or accrued taxes). Enter the amounts in both columns (d) and (e). The balancing of this page is not affected by the inclusion of these taxes.

3. Include in column (d) taxes charged during the year, taxes charged to operations and other accounts through (a) accruals credited to taxes accrued, (b) amounts credited to proportions of prepaid taxes chargeable to current year, and (c) taxes paid and charged direct to operations or accounts other than accrued and prepaid tax accounts.

4. List the aggregate of each kind of tax in such manner that the total tax for each State and subdivision can readily be ascertained.

(Continued on page 259.)

Line No.	Kind of Tax (See Instruction 5) (a)		Balance at Beginning of Year: Taxes Accrued (b)	Balance at Beginning of Year: Prepaid Taxes (c)	Taxes Charged During Year (d)	Paid During Year (e)	Adjustments (f)	Balance at End of Year: Taxes Accrued (Account 236) (g)	Balance at End of Year: Prepaid Taxes (Incl. in Account 165) (h)
1	Federal:								
2	Income Tax	(165)(1976)	51,803		(12,155)	39,648			
3	" "	(165)(1977)	(20,182)		103,187	83,005			
4	" "	(165)(1978)	750,525		(228,147)			522,378	
5	" "	(165)(1979)	343,883		1,020,104			1,363,987	
6	" "	(165)(1980)	284,382		206,666			491,048	
7	" "	(165)(1981)	310,802		206,666			517,468	
8	" "	(165)(1982)	3,254,277		875,172	5,428,013		(1,298,564)	
9	" "	(165)(1983)			(7,705,630)	(5,594,000)		(2,111,630)	
10	Unemploy. Ins.	(2)(1982)	1,191			1,191			
11	" "	(2)(1983)			78,556	77,148		1,408	
12	Ins. Contr. Act	(1983)			2,413,895	2,413,895			
13	Use Tax-Mtr. Vehicle	(1983)			14,376	14,376			
14	Total Federal		4,976,681		(3,027,310)	2,463,276		(513,905)	
15	State - Washington:								
16	Prop. Tax	(3)(1981)	(1,246)		1,246				
17	" "	(3)(1982)	3,092,454		129,756	3,222,210			
18	" "	(3)(1983)			3,758,341	186		3,758,155	
19	Excise Tax	(1982)	889,000		50,543	939,543			
20	" "	(1983)			9,728,002	8,673,002		1,055,000	
21	Unemploy. Ins.	(1982)	15,179		247	15,426			
22	" "	(1983)			395,676	381,648		14,028	
23	Motor Vehicle	(1983)			120,786	120,786			
24	Total Washington		3,995,387		14,184,597	13,352,801		4,827,183	
25	State - Idaho:								
26	Income Tax	(465)(1982)	545,740		74,282	620,022			
27	" "	(465)(1983)			(206,397)			(206,397)	
28									

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The Washington Water Power Company	(1) [X] An Original (2) [ ] A Resubmission	April 30, 1984	Dec. 31, 19 83

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR

1. Give particulars (details) of the combined prepaid and accrued tax accounts and show the total taxes charged to operations and other accounts during the year. Do not include gasoline and other sales taxes which have been charged to the accounts to which the taxed material was charged. If the actual or estimated amounts of such taxes are known, show the amounts in a footnote and designate whether estimated or actual amounts.

2. Include on this page, taxes paid during the year and charged direct to final accounts, (not charged to prepaid or accrued taxes). Enter the amounts in both columns (d) and (e). The balancing of this page is not affected by the inclusion of these taxes.

3. Include in column (d) taxes charged during the year, taxes charged to operations and other accounts through (a) accruals credited to taxes accrued, (b) amounts credited to proportions of prepaid taxes chargeable to current year, and (c) taxes paid and charged direct to operations or accounts other than accrued and prepaid tax accounts.

4. List the aggregate of each kind of tax in such manner that the total tax for each State and subdivision can readily be ascertained.

(Continued on page 259.)

Line No.	Kind of Tax (See Instruction 5) (a)		Balance at Beginning of Year: Taxes Accrued (b)	Balance at Beginning of Year: Prepaid Taxes (c)	Taxes Charged During Year (d)	Paid During Year (e)	Adjustments (f)	Balance at End of Year: Taxes Accrued (Account 236) (g)	Balance at End of Year: Prepaid Taxes (Incl. in Account 165) (h)
1	State - Idaho: (contd.)								
2	Prop. Tax	(3)(1982)	514,763		(3)	514,760			
3	" "	(3)(1983)			1,204,004	602,017		601,987	
4	Kwh Tax	(1981)	10,000		(2,100)	7,900			
5	" "	(1982)	25,541		300,794	316,335		10,000	
6	" "	(1983)			64,194	41,855		22,339	
7	Unemploy. Tax	(2)(1982)	1,747		44	1,791			
8	" "	(2)(1983)			47,265	45,067		2,198	
9	Excise Tax	(1982)			2,013	2,013			
10	" "	(1983)			11,823	11,823			
11	Motor Vehicle	(1983)			9,948	9,948			
12	Mileage Use	(1982)			823	823			
13	" "	(1983)			1,040	1,040			
14	Total Idaho		1,097,791		1,507,730	2,175,394		430,127	
15	State - Montana:								
16	Income Tax	(4&5)(1982)	159,145		26,476	185,621			
17	" "	(4&5)(1983)			(51,850)			(51,850)	
18	Prop. Tax	(3)(1982)	678,408		416,144	1,094,552			
19	" "	(3)(1983)			3,697,700	1,849,371		1,848,329	
20	Unemploy. Ins.	(2)(1982)	110			110			
21	" "	(2)(1983)			5,557	5,283		274	
22	Kwh Tax	(1982)	54,634			54,634			
23	" "	(1983)			356,711	287,118		69,593	
24	Motor Vehicle	(1983)			636	636			
25	Total Montana		892,297		4,451,374	3,477,325		1,866,346	
26	County & Municipal:								
27	Occupation	(1983)			6,032,319	6,032,319			
28									

Name of Respondent	This Report Is	Date of Report (Mo, Da, Yr)	Year of Report
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TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR

1. Give particulars (details) of the combined prepaid and accrued tax accounts and show the total taxes charged to operations and other accounts during the year. Do not include gasoline and other sales taxes which have been charged to the accounts to which the taxed material was charged. If the actual or estimated amounts of such taxes are known, show the amounts in a footnote and designate whether estimated or actual amounts.

2. Include on this page, taxes paid during the year and charged direct to final accounts, (not charged to prepaid or accrued taxes). Enter the amounts in both columns (d) and (e). The balancing of this page is not affected by the inclusion of these taxes.

3. Include in column (d) taxes charged during the year, taxes charged to operations and other accounts through (a) accruals credited to taxes accrued, (b) amounts credited to proportions of prepaid taxes chargeable to current year, and (c) taxes paid and charged direct to operations or accounts other than accrued and prepaid tax accounts.

4. List the aggregate of each kind of tax in such manner that the total tax for each State and subdivision can readily be ascertained.

(Continued on page 259.)

Line No.	Kind of Tax (See Instruction 5) (a)		Balance at Beginning of Year: Taxes Accrued (b)	Balance at Beginning of Year: Prepaid Taxes (c)	Taxes Charged During Year (d)	Paid During Year (e)	Adjustments (f)	Balance at End of Year: Taxes Accrued (Account 236) (g)	Balance at End of Year: Prepaid Taxes (Incl. in Account 165) (h)
1	County & Municipal: (contd.)								
2	Real Estate	(1983)			34,650	34,650			
3	Use of Streets	(1982)	20,920		4,305	25,225			
4	" " "	(1983)			10,032			10,032	
5	Paving Assessment	(1983)			3,868	3,868			
6	Spokane Bus. Lic.	(1983)			10,630	10,630			
7	Total Cty. & Mun.		20,920		6,095,804	6,106,692		10,032	
8	Canada:								
9	Income Tax	(1983)				2,659		(2,659)	
10	Total Canada					2,659		(2,659)	
11	TOTAL		10,983,076		23,212,195	27,578,147		6,617,124	
12									
13									
14	( ) Red Figure								
15									
16	Notes: (1) Allocation to utility departments based on net operating income, tax depreciation and allocated interest charges. Investment tax								
17	credit allocated directly to related departments.								
18	(2) Allocation to utility departments based on direct and allocated payroll.								
19									
20	(3) Allocation to utility departments based on direct and allocated property.								
21	(4) Allocation to utility department based on property, payroll and operating revenue.								
22	(5) Allocations to Account 409.2, Federal and State Income Taxes - Other based on taxable income.								
23									
24									
25									
26									
27									
28									

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
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TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

5. *If any tax (exclude Federal and state income taxes) covers more than one year, show the required information separately for each tax year, identifying the year in column (a).*

6. Enter all adjustments of the accrued and prepaid tax accounts in column (f) and explain each adjustment in a footnote. Designate debit adjustments by parentheses.

7. Do not include on this page entries with respect to deferred income taxes or taxes collected through payroll deductions or otherwise pending transmittal of such taxes to the taxing authority.

8. Enter accounts to which taxes charged were distributed in columns (i) thru (l). In column (i), report the amounts charged to Accounts 408.1 and 409.1 for Electric Department only. Group the amounts charged to 408.1, 409.1, 408.2 and 409.2 under other accounts in column (1). For taxes charged to other accounts or utility plant, show the number of the appropriate balance sheet account, plant account or subaccount.

9. For any tax apportioned to more than one utility department or account, state in a footnote the basis (necessity) of apportioning such tax.

DISTRIBUTION OF TAXES CHARGED *(Show utility department where applicable and account charged.)*

Line No.	Electric (Account 408.1, 409.1) (i)	Extraordinary Items (Account 409.3) (j)	Adjustment to Ret. Earnings (Account 439) (k)	Other (l)
1	Schedule attached	- See page 259-A		
2				
3				
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				
28	TOTAL			

THE WASHINGTON WATER POWER COMPANY
TAX ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)
Page 259-A
1983

	Year	Electric Accounts 408-409	Gas Accounts 408-409	Steam Accounts 408-409	Water Accounts 408-409	Nonoperating Accounts 408-409	Account 101	Account 108	Account 118	Account 119	Account 146	Misc.	Total
Federal:													
Income Tax	1976	(11,164)	(991)										(12,155)
" "	1977	39,186	(18,904)			83,005							103,187
" "	1978	(192,762)	(35,385)										(228,147)
" "	1979	319,088	701,016										1,020,104
" "	1980	350,818	(144,150)										206,666
" "	1981	200,900	5,766										206,666
" "	1982	(2,038,550)	(473,283)	(2,809)								3,389,814(5)	875,172
" "	1983	(7,809,371)	86,378	2,140	1,815	(97,526)						110,834(5)	(7,705,830)
Unemployment Ins.	1983	43,043	8,621	539	478		19,097	1,108	1,813	67	3,990		78,556
Insurance Contribution Act	1983	1,328,434	265,922	16,627	4,194		589,386	34,194	49,792	2,087	123,279		2,413,895
Use Tax-Motor Vehicle	1983											14,376(1)	14,376
State of Washington:													
Property Tax	1981				1,246								1,246
" "	1982	9,725	(39,102)	(12,481)	(94,348)		265,972						129,756
" "	1983	2,267,200	585,796	24,000			881,191					154(2)	3,758,341
Excise Tax	1982	50,543											50,543
" "	1983	6,235,985	3,383,108	21,878	10,776		57,468		6,278			12,509(3)	9,728,002
Unemployment Ins.	1982	150	27	2	3		56	3	6				247
" "	1983	212,639	44,156	3,083	1,684		94,133	5,511	9,851	394	24,125		395,876
Motor Vehicle	1983											120,788(1)	120,788
State of Idaho:													
Income Tax	1982	70,917	3,365										74,282
" "	1983	(178,160)	(26,669)			(1,568)							(206,397)
Property Tax	1982	375	(378)										(3)
" "	1983	1,037,096	166,908										1,204,004
Kuhr Tax	1981	(2,100)											(2,100)
" "	1982	300,794											300,794
" "	1983	64,194											64,194
Unemployment Ins.	1982	27	5				10	1	1				44
" "	1983	28,585	5,181				12,200	701	565	23			47,285
Excise Tax	1982	135	32				1,848						2,013
" "	1983	2,151	515				5,290		75			3,792(4)	11,823
Motor Vehicle	1983											9,948(1)	9,948
Mileage Use	1982											823(1)	823
" "	1983											1,040(1)	1,040
State of Montana:													
Income Tax	1982	26,476											26,476
" "	1983	(51,456)				(394)							(51,850)
Property Tax	1982	(50,923)					467,067						416,144
" "	1983	1,922,300					1,775,400						3,697,700
Unemployment Ins.	1983	3,789					1,768						5,557
Kuhr Tax	1983	356,711											356,711
Motor Vehicle	1983											636(1)	636
County & Municipal:													
Occupation	1983	4,714,340	1,236,445	70,716	10,818								6,032,319
Real Estate	1983	13					1,118		107			33,412	34,650
Use of Streets	1982			4,305									4,305
" " "	1983			10,032									10,032
Paving Assessment	1983	3,868											3,868
Spokane Bus. Lic.	1983	7,670	2,859	101									10,630
Total		9,282,844	5,757,168	138,123	(83,234)	(16,483)	4,172,002	41,518	68,388	2,551	151,394	3,698,124	23,212,195

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( ) Red Figure
Notes: (1) Charged to Acct. 184.1
(2) Charged to Acct. 418.24
(3) Charged $1,660 to Acct. 184.1; $9,412 to various operating accts. and $1,437 to Acct. 183
(4) Charged $203 to Acct. 184.1; $3,589 to various operating accts.
(5) Represents Investment Tax Credit and Taxes Accrued For WP Energy Co.

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RECONCILIATION OF REPORTED NET INCOME WITH TAXABLE INCOME FOR FEDERAL INCOME TAXES

1. Report the reconciliation of reported net income for the year with taxable income used in computing Federal income tax accruals and show computation of such tax accruals. Include in the reconciliation, as far as practicable, the same detail as furnished on Schedule M 1 of the tax return for the year. Submit a reconciliation even though there is no taxable income for the year. Indicate clearly the nature of each reconciling amount.

2. If the utility is a member of a group which files a consolidated Federal tax return, reconcile reported net income with taxable net income as if a separate return were to be filed, indicating, however, intercompany amounts to be eliminated in such a consolidated return. State names of group members, tax assigned to each group member, and basis of allocation, assignment, or sharing of the consolidated tax among the group members.

3. A substitute page, designed to meet a particular need of a company, may be used as long as the data is consistent and meets the requirements of the above instructions.

Line No.	Particulars (Details) (a)	Amount (b)
1	Net Income for the Year (Page 117)	67,707,240
2	Reconciling Items for the Year	
3	Federal income tax accrual estimate	(9,034,785)
4	Taxable Income Not Reported on Books	
5	Pollution control bond interest income	1,189,363
6	BPA excess reimbursement	205,306
7	Federal tax audit revenue adjustment	449,273
8		
9	Deductions Recorded on Books Not Deducted for Return	
10	Book depreciation and amortization	17,540,709
11	Deferred compensation and interest	31,467
12		
13		
14	Income Recorded on Books Not Included in Return	
15	Equity in subsidiary earnings	(6,104,751)
16	AFUDC	(33,092,784)
17	Gain on redemption of sinking fund debentures	(49,739)
18	Billing cycle revenues adjusted to calendar	(3,082,677)
19	Deductions on Return Not Charged Against Book Income	
20	Taxes capitalized	(4,284,459)
21	Tax depreciation and amortization	(30,681,700)
22	Employee benefits capitalized	(1,807,827)
23	Terminated nuclear project - Skagit	(28,185,460)
24	Charges: Leased equipment	(175,012)
25	Weatherization grants	(11,124,480)
26	Other nonrecurring items	(674,950)
27	Federal Tax Net Income	(41,175,266)
28	Show Computation of Tax:	
29	Net income per above	(41,175,266)
30	85% of dividends received	(122)
31	Adjusted net taxable income	(41,175,388)
32		
33	46% of adjusted net taxable income	(18,940,679)
34	Multiple corporation surtax exemption	(19,248)
35	Investment tax credit claimed	-0-
36	46% of: Miscellaneous disallowances	480,240
37	Investment tax credit adjustment - net	(2,039,676)
38	Deferred Federal income tax	7,763,561
39	Investment tax credit recapture - Skagit - flow-through	(294,350)
40	Investment tax credit recapture - Skagit - Deferred	2,015,989
41	Redetermination of prior period ITC resulting from NOL carryback	2,629,000
42	Adjustment of prior year's Federal income tax accrual	(1,218,322)
43		
44	Federal income tax accrual estimate - current year	(9,034,785)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
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ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255)

Report below information applicable to Account 255. Where appropriate, segregate the balances and transactions by utility and nonutility operations. Explain by footnote any correction adjustments to the account balance shown in column (g). Include in column (i) the average period over which the tax credits are amortized.

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	Deferred for Year: Account No. (c)	Deferred for Year: Amount (d)	Allocations to Current Year's Income: Account No. (e)	Allocations to Current Year's Income: Amount (f)	Adjustments (g)	Balance at End of Year (h)	Average Period of Allocation to Income (i)
1	Electric Utility								
2	3%								
3	4%								
4	10%	38,038,995			411.4	429,621	1,111,623 (1)	38,288,249	45 yrs.
5	10%						4,212,241 (2)		
6							(2,629,000)(4)		
7							(2,015,989)(5)		
8	TOTAL	38,038,995				429,621	678,875	38,288,249	
9	Other *(List separately and show 3%, 4%, 7%, 10% and TOTAL)*								
10	Gas property (10%)	1,016,550			411.4	28,125	(78,214)(1)	910,211	35 yrs.
11	Steam heat property (10%)	120,064			411.4	3,456	2,809 (1)	119,417	39 yrs.
12	Water property (10%)(3)	364,106				364,106(3)			
13	Consolidated subsidiary								
14	property (2)	4,212,241					(4,212,241)(2)		
15	Total Company	43,751,956				825,308	(3,608,771)	39,317,877	

Notes:
(1) Represents adjustment for 1982 to actual ITC per Federal return.
(2) Represents Investment Tax Credit for WP Energy Co., subsequently merged into WWP. ITC was transferred to Electric Utility.
(3) Water system was sold on February 28, 1983.
(4) A net operating loss carry back from 1983 to 1982 caused a redetermination of 1982 ITC. This represents the amount of ITC generated in 1982 subsequently determined to be subject to carry forward.
(5) Skagit Nuclear Plant abandonment in 1983 caused recapture to ITC previously claimed and deferred.

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
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OTHER DEFERRED CREDITS (Account 253)

1. Report below the particulars (details) called for concerning other deferred credits.
2. For any deferred credit being amortized, show the period of amortization.
3. **Minor items (5% of the Balance End of Year for Account 253 or amounts less than $10,000, whichever is greater) may be grouped by classes.**

Line No.	Description of Other Deferred Credit (a)	Balance at Beginning of Year (b)	DEBITS Contra Account (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Year (f)
1	Unearned interest -					
2	Customer wiring and installa-					
3	tion contracts	69,569	419	19,455	44,495	94,609
4						
5	Water amortization -		3403	8,273		
6	Plant in Service (1)	813,525				
7			186.2	805,252		
8	Gas Exploration Advance -					
9	Develop. Assoc., Inc. (2)	(83,358)	1798	32,886	116,244	
10						
11	Gas Refund - Washington		1804	239,425	1,565,344	1,325,919
12						
13	Gas Refund - Idaho		1804	393,749	675,790	282,041
14						
15	Accum. Credits Allowed under					
16	BPA Residential Exchange					
17	Agreement - Washington	(61,187)	142.1	85,900		(147,087)
18						
19	BPA Conservation Program					
20	Excess Reimbursement (3)	1,486,837	908	563,164	205,306	1,128,979
21						
22	Deferred Compensation (4)				31,467	31,467
23						
24						
25	Notes: (1) The unamortized balance in this account was transferred to other deferred debits in					
26	February 1983, in conjunction with the sale of the water system on February 28, 1983.					
27						
28	(2) Due to the continuing debit balance in this account, it was reclassified as a deferred					
29	debit in June 1983.					
30						
31	(3) Period of amortization is 36 months, January 1, 1983 through December 31, 1985.					
32						
33	(4) Salary benefits plus interest, deferred by retired officers. The contra account is					
34	cash when scheduled payments are made.					
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47	TOTAL	2,225,386				2,715,928

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
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ACCUMULATED DEFERRED INCOME TAXES—OTHER PROPERTY (Account 282)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes relating to property not subject to accelerated amortization.
2. For Other *(Specify)*, include deferrals relating to other

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited (Account 410.1) (c)	Amounts Credited (Account 411.1) (d)
1	Account 282 (1)			
2	Electric	2,553,140	3,855,510	
3	Gas	121,068	126,992	
4	Other *(Define)*	58,286	1,272	
5	TOTAL *(Enter Total of lines 2 thru 4)*	2,732,494	3,983,774	
6	Other *(Specify)* Abandonment of Skagit Nuclear Project		12,965,311	
7	Water System Sale			
8				
9	TOTAL Account 282 *(Enter Total of lines 5 thru 8)*	2,732,494	16,949,085	
10	Classification of TOTAL			
11	Federal Income Tax	2,732,494	16,949,085	
12	State Income Tax			
13	Local Income Tax			

NOTES

Notes: (1) Deferred taxes relate to normalization of ACRS depreciation as required for utilities under provisions of the Economic Recovery Tax Act of 1981.

(2) Represents adjustment from prior year book estimate to actual per tax return.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
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ACCUMULATED DEFERRED INCOME TAXES—OTHER PROPERTY (Account 282) (Continued)

income and deductions.
3. Use separate pages as required.

CHANGES DURING YEAR		ADJUSTMENTS					
		Debits		Credits			
Amounts Debited (Account 410.2) (e)	Amounts Credited (Account 411.2) (f)	Acct. No. (g)	Amount (h)	Acct. No. (i)	Amount (j)	Balance at End of Year (k)	Line No.
							1
				410.1	120,209	6,288,441	2
		410.1	8,581			256,641	3
		410.1	11,494			71,052	4
			20,075		120,209	6,616,134	5
						12,965,311	6
		410.1	28,355	186	28,355		7
							8
			48,430 (2)		148,564 (2)	19,581,445	9
							10
			48,430 (2)		148,564 (2)	19,581,445	11
							12
							13

NOTES (Continued)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
The Washington Water Power Company	(1) [X] An Original (2) [ ] A Resubmission	April 30, 1984	Dec. 31, 1983

ELECTRIC OPERATING REVENUES (Account 400)

1. Report below operating revenues for each prescribed account, and manufactured gas revenues in total.
2. Report number of customers, columns (f) and (g), on the basis of meters, in addition to the number of flat rate accounts; except that where separate meter readings are added for billing purposes, one customer should be counted for each group of meters added. The average number of customers means the average of twelve figures at the close of each month.
3. If previous year (columns (c), (e), and (g)), are not derived from previously reported figures, explain any inconsistencies in a footnote.
4. *Commercial and Industrial Sales,* Account 442, may be classified according to the basis of classification (Small or Commercial, and Large or Industrial) regularly used by the respondent if such basis of classification is not generally greater than 1000 Kw of demand. (See Account 442 of the Uniform System of Accounts. Explain basis of classification in a footnote.)
5. See page 108, Important Changes During Year, for important new territory added and important rate increases or decreases.
6. For lines 2, 4, 5, and 6, see page 304 for amounts relating to unbilled revenue by accounts.
7. Include unmetered sales. Provide details of such sales in a footnote.

Line No.	Title of Account (a)	OPERATING REVENUES: Amount for Year (b)	OPERATING REVENUES: Amount for Previous Year (c)	MEGAWATT HOURS SOLD: Amount for Year (d)	MEGAWATT HOURS SOLD: Amount for Previous Year (e)	AVG. NO. OF CUSTOMERS PER MONTH: Number for Year (f)	AVG. NO. OF CUSTOMERS PER MONTH: Number for Previous Year (g)
1	Sales of Electricity						
2	(440) Residential Sales	86,527,710	78,924,044	2,911,547	3,096,662	205,533	203,444
3	(442) Commercial and Industrial Sales (3)						
4	Small (or Commercial) *(See Instr. 4)*	56,065,647	49,596,025	1,679,181	1,670,302	23,555	23,310
5	Large (or Industrial) *(See Instr. 4)*	26,886,839	24,994,407	1,349,331	1,354,129	1,024	1,044
6	(444) Public Street and Highway Lighting	2,526,061	2,401,241	30,387	36,871	293	266
7	(445) Other Sales to Public Authorities						
8	(446) Sales to Railroads and Railways						
9	(448) Interdepartmental Sales						
10	TOTAL Sales to Ultimate Consumers	172,006,257	155,915,717	5,970,446	6,157,964	230,405	228,064
11	(447) Sales for Resale	40,873,753	46,349,097	3,006,924	2,837,290	15	15
12	TOTAL Sales of Electricity	212,880,010(1)	202,264,814	8,977,370(2)	8,995,254	230,420	228,079
13	Other Operating Revenues						
14	(450) Forfeited Discounts						
15	(451) Miscellaneous Service Revenues	83,682	78,923				
16	(453) Sales of Water and Water Power	390,654	422,832				
17	(454) Rent from Electric Property	705,060	419,116				
18	(455) Interdepartmental Rents						
19	(456) Other Electric Revenues	1,391,326	2,154,893				
20							
21							
22							
23							
24	TOTAL Other Operating Revenues	2,570,722	3,075,764				
25	TOTAL Electric Operating Revenues	215,450,732	205,340,578				

Notes:

(1) Includes $ -0- unbilled revenues.

(2) Includes -0- MWH relating to unbilled revenues.

(3) Segregation of Commercial and Industrial made on the basis of utilization of energy and not on size of account.

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
The Washington Water Power Company	(1) [X] An Original (2) [ ] A Resubmission	April 30, 1984	Dec. 31, 1983

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the kWh of electricity sold, revenue, average number of customers, average kWh per customer, and average revenue per kWh, excluding data for Sales for Resale is reported on pages 310-311.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," page 301. If the sales under any rate schedule are classified in more than one revenue account, list the rate schedule and sales data under each applicable revenue account subheading.
3. *Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.*
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate Schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales per Customer (e)	Revenue per KWh Sold (f)
1	Residential Sales (440)					
2	1 Residential Service	2,812,400	80,243,617	200,591	14,021	2.85¢
3	11 General Service	163	6,307	14	11,643	3.87
4	12 Res. & Farm Gen. Service	29,480	1,279,241	3,786	7,787	4.34
5	15 Comm. Wtr. Htg. Service	4,801	135,243	582	8,249	2.82
6	22 Res. & Farm Lg. Gen. Svce.	17,285	529,502	42	411,548	3.06
7	32 Res. & Farm Pumping Svce.	38,382	1,056,070	517	74,240	2.75
8	47 Area Lighting		107			
9	48 Res. & Farm Area Lighting	9,036	743,662	1	9,036,000	8.23
10	58 Tax Adjustment		2,534,160			
11	59 BPA Adjustment		(199)			
12	Total	2,911,547	86,527,710	205,533	14,166	2.97¢
13	Commercial Sales (442)					
14	11 General Service	408,494	16,953,902	20,386	20,038	4.15¢
15	12 Res. & Farm Gen. Service	11	415	1	11,000	3.77
16	15 Comm. Wtr. Htg. Service	3,318	99,046	580	5,721	2.99
17	19 Contract - General Service	831	17,228	7	118,714	2.07
18	21 Large General Service	1,041,117	31,811,637	2,515	413,963	3.06
19	25 Extra Lg. Gen. Service	207,042	4,067,058	8	25,880,250	1.96
20	31 Pumping Service	6,160	174,771	56	110,000	2.84
21	45 Cust.-Owned St. Lt.					
22	Energy Service	41	877	1	41,000	2.14
23	47 Area Lighting	12,167	828,833	1	12,167,000	6.81
24	48 Res. & Farm Area Lighting		13			
25	58 Tax Adjustment		2,111,867			
26	Total	1,679,181	56,065,647	23,555	71,288	3.34¢
27	Industrial Sales (442)					
28	11 General Service	7,333	341,238	266	27,568	4.65¢
29	15 Comm. Wtr. Htg. Service		63			
30	21 Large General Service	317,705	9,161,260	244	1,302,070	2.88
31	25 Extra Lg. General Service	974,780	15,756,856	13	74,983,077	1.62
32	29 Contract - Lg. Gen. Service	(5,005)	(86,239)	1	(5,005,000)	1.72
33	31 Pumping Service	53,838	1,498,079	499	107,892	2.78
34	47 Area Lighting	680	46,978	1	680,000	6.91
35	58 Tax Adjustment		168,604			
36	Total	1,349,331	26,886,839	1,024	1,317,706	1.99¢
37						
38						
39						
40						
41	Total Billed					
42	Total Unbilled Rev. *(See Instr. 6)*	Not Calculated				
43	TOTAL					

Attachment 5-4
Forecasts and Backcasts of Average System Costs and Loads for FY 2002 Through 2008
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
The Washington Water Power Company	(1) [X] An Original (2) [ ] A Resubmission	April 30, 1984	Dec. 31, 1983

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the kWh of electricity sold, revenue, average number of customers, average kWh per customer, and average revenue per kWh, excluding data for Sales for Resale is reported on pages 310-311.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," page 301. If the sales under any rate schedule are classified in more than one revenue account, list the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate Schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales per Customer (e)	Revenue per KWh Sold (f)
1	Street and Highway Lighting (444)					
2	11 General Service	272	10,645	36	7,556	3.91¢
3	41 Co.-Owned St. Lt. Service	18,632	1,435,206	99	188,202	7.70
4	42 Co.-Owned St. Lt. Service -					
5	High-Press. Sod. Vap.	4,801	762,195	107	44,869	15.88
6	43 Cust.-Owned St. Lt. Energy					
7	and Maint. Service	1,161	50,562	16	72,563	4.36
8	44 Cust.-Owned St. Lt. Energy					
9	and Maint. Svce. - High-					
10	Press. Sod. Vap.	109	8,972	3	36,333	8.23
11	45 Cust.-Owned St. Lt. Enrg. Svc.	4,000	104,938	24	166,667	2.62
12	46 Cust.-Owned St. Lt. Enrg. Svc. -					
13	High Press. Sod. Vap.	1,412	54,658	8	176,500	3.87
14	58 Tax Adjustment		98,885			
15	Total	30,387	2,526,061	293	103,710	8.31¢
16	Other Sales to Public Authorities (445)					
17	None					
18						
19	Sales for Resale (447)(1)					
20	61 Sales to Other Utls. - WA	2,382,614	33,118,921	9	264,735,000	1.39¢
21	61 Sales to Other Utls. - ID	153,622	2,688,634	4	38,405,250	1.75
22	61 Sales to Other Utls. - MT	470,688	5,066,198	2	235,344,000	1.08
23	Total	3,006,924	40,873,753	15	200,461,600	1.36¢
24						
25						
26	Note: (1) Schedule 61 is a state assigned rate schedule for Sales for Resale.					
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	Total Billed	[illegible]	[illegible]	[illegible]	[illegible]	2.37¢
42	Total Unbilled Rev. *(See Instr. 6)*	Not Calculated				
43	TOTAL	8,977,370	212,880,010	230,420	38,961	2.37¢

Attachment 5-4
Forecasts and Backcasts of Average System Costs and Loads for FY2002 Through 2008
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
The Washington Water Power Company	(1) [X] An Original (2) [ ] A Resubmission	April 30, 1984	Dec 31, 19 83

SALES FOR RESALE (Account 447)

1. Report sales during the year to other electric utilities and to cities or other public authorities for distribution to ultimate consumers.

2. Provide in column (a) subheadings and classify sales as to (1) Associated Utilities, (2) Nonassociated Utilities, (3) Municipalities, (4) Cooperatives, and (5) Other Public Authorities. For *each sale* designate statistical classification in column (b) using the following codes: FP, firm power supplying total system requirements of customer or total requirements at a specific point of delivery; FP(C), firm power supplying total system requirements of customer or total requirements at a specific point of delivery with credit allowed customer for available standby; FP(P), firm power supplementing customer's own generation or other purchases; DP, dump power; O, other. Describe in a footnote the nature of any sales classified as Other Power. Place an "x" in column (c) if sale involves export across a state line. Group together sales coded "x" in column (c) by state (or county) of origin identified in column (e), providing a subtotal for each state (or county) of delivery in columns (l) and (p).

Line No.	Sales To (a)	Statistical Classification (b)	Export Across State Lines (c)	FERC Rate Schedule No. (d)	Point of Delivery (State or county) (e)	Substation Ownership (If applicable) (f)	MW or MVa of Demand (Specify which): Contract Demand (g)	Average Monthly Maximum Demand (h)	Annual Maximum Demand (i)
1	NONASSOCIATED UTILITIES								
2	San Diego Gas & Elec.(2,3)	DP		88/64	Various	CS-RS			
3	Modern Elec. Wtr. Co.	FP		61	Opportunity, WA	RS	(Note 1)	28.5	40.5
4	Pac. Gas & Elec. Co.(2,3)	DP		122	Various	CS-RS			
5	So. Cal. Edison Co. (2,3)	DP		88/114/123	Various	CS-RS			
6	Sierra Pac. Pwr. Co. (2)	DP		87.1	Various	CS-RS			
7	Portland G.E. (2)	DP		87.1	Various	RS			
8	Pac. Pwr. & Lt. Co. (2)	DP		87.1	Various	RS			
9	Pac. Pwr. & Lt. Co. (2)	FP		61	Sandpoint, ID	CS-RS			
10	Citizens Util. Co.	FP		61	Mullan & Wallace, ID	RS	(Note 1)	6.5	6.2
11	Montana Pwr. Co. (2)	DP		87.1	Various	RS			
12	Utah Pwr. Co. (2)	DP		87.1	Hot Springs, MT	RS			
13	Chelan Co. PUD #1 (2)	FP(P)		None	Various	CS-RS			
14	Colokum (2)	DP		97	Various	CS-RS			
15	Total								
16									
17	MUNICIPALITIES								
18	City of Chewelah	FP		61	Chewelah, WA	RS	(Note 1)	4.1	6.2
19	Glendale Pub. Svc. Dpt.(2,3)	DP		135	Various	CS-RS			
20	Village of Plummer	FP		61	Plummer, ID	RS	(Note 1)	2.6	4.0
21	City of Burbank (2,3)	DP		134	Various	CS-RS			
22	Pasadena Wtr.& Pwr.Dpt. (2)	DP		136	Various	CS-RS			
23	L.A. Dpt. Wtr. & Pwr. (2,3)	DP		(4)	Various	CS-RS			
24	Cty. of Seattle-Dpt.of Lt.(2,3)	FP		None	Priest Rapids, WA	RS			
25	Total								
26									
27	OTHER PUBLIC AUTHORITIES								
28	Bonneville Pwr. Adm. (2,3)	DP		None	Various	CS-RS			
29	Western Area Pwr. Adm. (2,3)	DP		137	Various	CS-RS			
30	Total								
31									
32	TOTAL SALES FOR RESALE								
33									
34	Notes: (1) Not less than 75% of demand of any previous 11 months.								
35	(2) Included in Sales Outside System, Page 401-A (2,767 Mwhrs).								
36	(3) Delivered through the facilities of Bonneville Power Administration.								
37	(4) Pending.								
38									
39									
40									
41									
42									
43									
44									

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
The Washington Water Power Company	(1) [X] An Original (2) [ ] A Resubmission	April 30, 1984	Dec. 31, 19 83

SALES FOR RESALE (Account 447) (Continued)

3. Report separately firm, dump, and other power sold to the same utility.
4. If delivery is made at a substation, indicate ownership in column (f), using the following codes: RS, respondent owned or leased; CS, customer owned or leased.
5. If a fixed number of megawatts of maximum demand is specified in the power contract as a basis of billings to the customer, enter this number in column (g). Base the number of megawatts of maximum demand entered in columns (h) and (i) on actual monthly readings. Furnish these figures whether or not they are used in the determination of demand charges. Show in column (j) type of demand reading (i.e., instantaneous, 15, 30, or 60 minutes integrated).
6. For column (l) enter the number of megawatt hours shown on the bills rendered to the purchasers.
7. Explain in a footnote any amounts entered in column (o), such as fuel or other adjustments.
8. If a contract covers several points of delivery and small amounts of electric energy are delivered at each point, such sales may be grouped.

Type of Demand Reading (j)	Voltage at Which Delivered (k)	Megawatt Hours (l)	REVENUE: Demand Charges (m)	REVENUE: Energy (n)	REVENUE: Other Charges (o)	REVENUE: Total (p)	Line No.
							1
60 Min.	230 Kv	746,972		10,286,751		10,286,751	2
15 Min.	4-13 Kv	169,041	838,515	1,937,447		2,775,962	3
60 Min.	115-230 Kv	26,693		578,934		578,934	4
60 Min.	115-230 Kv	412,378		9,757,588		9,757,588	5
60 Min.	115-230 Kv	37,674		296,239		296,239	6
60 Min.	115-230 Kv	280,021		1,907,826		1,907,826	7
60 Min.	115-230 Kv	2,010		11,498		11,498	8
60 Min.	60-230 Kv	103,533	607,500	1,227,538		1,835,038	9
15 Min.	13 Kv	37,402	200,669	429,506		630,175	10
60 Min.	115-230 Kv	77,569	1,800,000	472,486		2,272,486	11
60 Min.	230 Kv	393,119		2,793,712		2,793,712	12
60 Min.	115-230 Kv	145,171		734,241		734,241	13
60 Min.	230 Kv	15,997		412,458		412,458	14
		2,447,580	3,446,684	30,846,224		34,292,908	15
							16
							17
15 Min.	4 Kv	20,764	117,242	239,059		356,301	18
60 Min.	230 Kv	5,394		109,428		109,428	19
15 Min.	115-230 Kv	12,686	76,147	147,274		223,421	20
60 Min.	115-230 Kv	2,825		55,587		55,587	21
60 Min.	115-230 Kv	3,525		72,013		72,013	22
60 Min.	115-230 Kv	55,263		1,136,196		1,136,196	23
60 Min.	115-230 Kv			347,500		347,500	24
		100,457	193,389	2,107,057		2,300,446	25
							26
							27
60 Min.	115-230 Kv	450,638		4,083,248		4,083,248	28
60 Min.	115-230 Kv	8,249		197,151		197,151	29
		458,887		4,280,399		4,280,399	30
							31
		3,006,924	3,640,073	37,233,680		40,873,753	32
							33
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
The Washington Water Power Company	(1) [X] An Original (2) [ ] A Resubmission	April 30, 1984	Dec. 31, 19 83

ELECTRIC OPERATION AND MAINTENANCE EXPENSES

If the amount for previous year is not derived from previously reported figures, explain in footnotes.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
1	1. POWER PRODUCTION EXPENSES		
2	A. Steam Power Generation		
3	Operation		
4	(500) Operation Supervision and Engineering	275,137	255,807
5	(501) Fuel	16,201,634	10,616,287
6	(502) Steam Expenses	273,504	242,050
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred—Cr.		
9	(505) Electric Expenses	197,006	163,984
10	(506) Miscellaneous Steam Power Expenses	500,106	508,763
11	(507) Rents	4,646	3,616
12	TOTAL Operation *(Enter Total of lines 4 thru 11)*	17,452,033	11,790,507
13	Maintenance		
14	(510) Maintenance Supervision and Engineering	309,248	262,824
15	(511) Maintenance of Structures	189,019	190,947
16	(512) Maintenance of Boiler Plant	1,448,451	2,217,740
17	(513) Maintenance of Electric Plant	222,498	168,747
18	(514) Maintenance of Miscellaneous Steam Plant	181,716	44,208
19	TOTAL Maintenance *(Enter Total of lines 14 thru 18)*	2,350,932	2,884,466
20	TOTAL Power Production Expenses—Steam Power *(Enter Total of lines 12 and 19)*	19,802,965	14,674,973
21	B. Nuclear Power Generation		
22	Operation		
23	(517) Operation Supervision and Engineering		
24	(518) Fuel		
25	(519) Coolants and Water		
26	(520) Steam Expenses		
27	(521) Steam from Other Sources		
28	(Less) (522) Steam Transferred—Cr.		
29	(523) Electric Expenses		
30	(524) Miscellaneous Nuclear Power Expenses		
31	(525) Rents		
32	TOTAL Operation *(Enter Total of lines 23 thru 31)*		
33	Maintenance		
34	(528) Maintenance Supervision and Engineering		
35	(529) Maintenance of Structures		
36	(530) Maintenance of Reactor Plant Equipment		
37	(531) Maintenance of Electric Plant		
38	(532) Maintenance of Miscellaneous Nuclear Plant		
39	TOTAL Maintenance *(Enter Total of lines 34 thru 38)*		
40	TOTAL Power Production Expenses—Nuclear Power *(Enter Total of lines 32 and 39)*		
41	C. Hydraulic Power Generation		
42	Operation		
43	(535) Operation Supervision and Engineering	901,447	838,805
44	(536) Water for Power	161,500	485,937
45	(537) Hydraulic Expenses	82,839	84,536
46	(538) Electric Expenses	1,287,526	1,242,454
47	(539) Miscellaneous Hydraulic Power Generation Expenses	302,966	323,796
48	(540) Rents	21,634	39,422
49	TOTAL Operation *(Enter Total of lines 43 thru 48)*	2,757,912	3,014,950

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
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ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

Line No.	Account *(a)*	Amount for Current Year *(b)*	Amount for Previous Year *(c)*
50	C. Hydraulic Power Generation (Continued)		
51	Maintenance		
52	(541) Maintenance Supervision and Engineering	97,845	90,472
53	(542) Maintenance of Structures	83,836	80,609
54	(543) Maintenance of Reservoirs, Dams, and Waterways	338,918	399,348
55	(544) Maintenance of Electric Plant	561,081	647,464
56	(545) Maintenance of Miscellaneous Hydraulic Plant	33,163	45,109
57	TOTAL Maintenance *(Enter Total of lines 52 thru 56)*	1,114,843	1,263,002
58	TOTAL Power Production Expenses--Hydraulic Power *(Enter Total of lines 49 and 57)*	3,872,755	4,277,952
59	D. Other Power Generation		
60	Operation		
61	(546) Operation Supervision and Engineering	2,957	28,995
62	(547) Fuel	239,407	806,868
63	(548) Generation Expenses	30,637	32,813
64	(549) Miscellaneous Other Power Generation Expenses	4,752	2,279
65	(550) Rents		26,028
66	TOTAL Operation *(Enter Total of lines 61 thru 65)*	277,753	896,983
67	Maintenance		
68	(551) Maintenance Supervision and Engineering	814	2,396
69	(552) Maintenance of Structures	322	9,133
70	(553) Maintenance of Generating and Electric Plant	16,083	211,522
71	(554) Maintenance of Miscellaneous Other Power Generation Plant	4,614	3,016
72	TOTAL Maintenance *(Enter Total of lines 68 thru 71)*	21,833	226,067
73	TOTAL Power Production Expenses—Other Power *(Enter Total of lines 66 and 72)*	299,586	1,123,050
74	E. Other Power Supply Expenses		
75	(555) Purchased Power	51,871,714	42,226,782
76	(556) System Control and Load Dispatching	489,506	451,887
77	(557) Other Expenses	41,564	87,213
78	TOTAL Other Power Supply Expenses *(Enter Total of lines 75 thru 77)*	52,402,784	42,765,882
79	TOTAL Power Production Expenses *(Enter Total of lines 20, 40, 58, 73, and 78)*	76,378,090	62,841,857
80	2. TRANSMISSION EXPENSES		
81	Operation		
82	(560) Operation Supervision and Engineering	156,826	109,517
83	(561) Load Dispatching	163,247	154,567
84	(562) Station Expenses	381,893	411,246
85	(563) Overhead Line Expenses	73,562	51,756
86	(564) Underground Line Expenses	122	197
87	(565) *Transmission of Electricity by Others*	4,401,232	2,142,871
88	(566) Miscellaneous Transmission Expenses	68,179	58,531
89	(567) Rents	5,900	9,535
90	TOTAL Operation *(Enter Total of lines 82 thru 89)*	5,250,961	2,938,220
91	Maintenance		
92	(568) Maintenance Supervision and Engineering	68,568	58,636
93	(569) Maintenance of Structures	6,277	7,056
94	(570) Maintenance of Station Equipment	344,468	368,310
95	(571) Maintenance of Overhead Lines	303,939	136,266
96	(572) Maintenance of Underground Lines	33,317	504
97	(573) Maintenance of Miscellaneous Transmission Plant	4,962	5,151
98	TOTAL Maintenance *(Enter Total of lines 92 thru 97)*	761,531	575,923
99	TOTAL Transmission Expenses *(Enter Total of lines 90 and 98)*	6,012,492	3,514,143
100	3. DISTRIBUTION EXPENSES		
101	Operation		
102	(580) Operation Supervision and Engineering	313,711	283,841
103	(581) Load Dispatching	65,174	61,057

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ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
104	3. DISTRIBUTION EXPENSES (Continued)		
105	(582) Station Expenses	501,005	498,146
106	(583) Overhead Line Expenses	515,487	601,785
107	(584) Underground Line Expenses	203,136	196,441
108	(585) Street Lighting and Signal System Expenses	145,466	102,262
109	(586) Meter Expenses	431,557	515,499
110	(587) Customer Installations Expenses	266,811	273,693
111	(588) Miscellaneous Distribution Expenses	415,977	443,869
112	(589) Rents	35,090	30,720
113	TOTAL Operation *(Enter Total of lines 102 thru 112)*	2,893,414	3,007,313
114	Maintenance		
115	(590) Maintenance Supervision and Engineering	243,802	215,318
116	(591) Maintenance of Structures	19,807	81,146
117	(592) Maintenance of Station Equipment	282,277	206,278
118	(593) Maintenance of Overhead Lines	2,168,189	2,238,580
119	(594) Maintenance of Underground Lines	400,622	400,376
120	(595) Maintenance of Line Transformers	272,355	283,862
121	(596) Maintenance of Street Lighting and Signal Systems	120,845	157,188
122	(597) Maintenance of Meters	96,631	129,190
123	(598) Maintenance of Miscellaneous Distribution Plant	11,826	12,108
124	TOTAL Maintenance *(Enter Total of lines 115 thru 123)*	3,616,354	3,724,046
125	TOTAL Distribution Expenses *(Enter Total of lines 113 and 124)*	6,509,768	6,731,359
126	4. CUSTOMER ACCOUNTS EXPENSES		
127	Operation		
128	(901) Supervision	242,086	225,536
129	(902) Meter Reading Expenses	1,573,660	1,561,037
130	(903) Customer Records and Collection Expenses	3,355,559	3,144,536
131	(904) Uncollectible Accounts	1,287,792	1,170,645
132	(905) Miscellaneous Customer Accounts Expenses	49,417	30,167
133	TOTAL Customer Accounts Expenses *(Enter Total of lines 128 thru 132)*	6,508,514	6,131,921
134	5. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
135	Operation		
136	(907) Supervision	153,720	108,246
137	(908) Customer Assistance Expenses	2,568,580	1,740,565
138	(909) Informational and Instructional Expenses	152,742	173,006
139	(910) Miscellaneous Customer Service and Informational Expenses	66,786	95,342
140	TOTAL Cust. Service and Informational Exp. *(Enter Total of lines 136 thru 139)*	2,941,828	2,117,159
141	6. SALES EXPENSES		
142	Operation		
143	(911) Supervision	35,096	18,644
144	(912) Demonstrating and Selling Expenses	96,665	96,151
145	(913) Advertising Expenses		
146	(916) Miscellaneous Sales Expenses	3,241	3,034
147	TOTAL Sales Expenses *(Enter Total of lines 143 thru 146)*	135,002	117,829
148	7. ADMINISTRATIVE AND GENERAL EXPENSES		
149	Operation		
150	(920) Administrative and General Salaries	3,597,282	3,463,899
151	(921) Office Supplies and Expenses	1,121,720	1,059,377
152	(Less) (922) Administrative Expenses Transferred—Cr.	327,776	192,440
153	(923) Outside Services Employed	826,421	697,856
154	(924) Property Insurance	172,418	280,407
155	(925) Injuries and Damages	926,748	1,559,566
156	(926) Employee Pensions and Benefits	4,719,169	4,480,347

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
The Washington Water Power Company	(1) ☒ An Original (2) ☐ A Resubmission	April 30, 1984	Dec. 31, 1983

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
157	7. ADMINISTRATIVE AND GENERAL EXPENSES (Continued)		
158	(927) Franchise Requirements	711,121	576,696
159	(928) Regulatory Commission Expenses	1,582,177	1,150,587
160	(Less) (929) Duplicate Charges—Cr.		
161	(930.1) General Advertising Expenses	49,516	54,668
162	(930.2) Miscellaneous General Expenses	2,247,716	2,190,946
163	(931) Rents	587,813	714,113
164	TOTAL Operation *(Enter Total of lines 150 thru 163)*	16,214,325	16,036,022
165	Maintenance		
166	(932) Maintenance of General Plant	871,318	819,676
167	TOTAL Administrative and General Expenses *(Enter Total of lines 164 thru 166)*	17,085,643	16,855,698
168	TOTAL Electric Operation and Maintenance Expenses *(Enter Total of lines 79, 99, 125, 133, 140, 147, and 167)*	115,571,337	98,309,966

NUMBER OF ELECTRIC DEPARTMENT EMPLOYEES

1. The data on number of employees should be reported for the payroll period ending nearest to October 31, or any payroll period ending 60 days before or after October 31.
2. If the respondent's payroll for the reporting period includes any special construction personnel, include such employees on line 3, and show the number of such special construction employees in a footnote.
3. The number of employees assignable to the electric department from joint functions of combination utilities may be determined by estimate, on the basis of employee equivalents. Show the estimated number of equivalent employees attributed to the electric department from joint functions.

1.	Payroll Period Ended (Date)	December 31, 1983
2.	Total Regular Full-Time Employees	601
3.	Total Part-Time and Temporary Employees	37
4.	"Allocation of General Employees"	510
5.	Total Employees (See Note 1)	1,148

Note: (1) For purposes of this report, joint function employees have been allocated to specific utility departments on the basis of labor dollars distributed.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
The Washington Water Power Company	(1) [X] An Original (2) [ ] A Resubmission	April 30, 1984	Dec. 31, 1983

PURCHASED POWER (Account 555)
(Except interchange power)

1. Report power purchased for resale during the year. Report on page 328 particulars (details) concerning interchange power transactions during the year; do not include such figures on this page.
2. Provide in column (a) subheadings and classify purchases as to: (1) Associated Utilities, (2) Nonassociated Utilities, (3) Associated Nonutilities, (4) Other Nonutilities, (5) Municipalities, (6) Cooperatives, and (7) Other Public Authorities. For each purchase designate statistical classification in column (b) using the following codes: FP, firm power; DP, dump or surplus power; O, other. Describe the nature of any purchases classified as Other Power. Enter an "x" in column (c) if purchase involves import across a state line.
3. Report separately firm, dump, and other power purchased

Line No.	Purchased From (a)	Statistical Classification (b)	Import Across State Lines (c)	FERC Rate Schedule No. of Seller (d)	Point of Receipt (e)	Substation Ownership (If applicable) (f)	MW or MVa of Demand (Specify which): Contract Demand (g)(7)	Average Monthly Maximum Demand (h)(7)	Annual Maximum Demand (i)(7)
1	NONASSOCIATED UTILITIES								
2	Pug. So. Pwr. & Lt.Co. (1)	DP		55	Various	RS			
3	Col. Stor. Pwr. Exch.	FP		None	Various	RS			
4	Pac. Pwr. & Lt. Co. (6)	DP			Various	RS			
5	Montana Pwr. Co. (1)	DP		M-1	Hot Sprgs.,MT; Burke, ID	RS			
6	Utah Pwr. & Lt.	DP		1-B	Hot Springs, MT	RS			
7	Idaho Pwr. Co. (2)	DP		1	Divide Creek, ID	RS			
8	So. Cal. Edison	FP		104	Various	RS			
9	Sierra Pac. Pwr. Co.	DP		2-RT	Various	RS			
10	Total								
11	OTHER PUBLIC AUTHORITIES								
12	Chelan Co. PUD #1	DP		None	Rocky Reach, WA	SS			
13	Chelan Co. PUD #1 (3)	FP		None	Chelan, WA	SS			
14	Chelan Co. PUD #1 (4)	FP		None	Rocky Reach, WA	SS			
15	Grant Co. PUD #2	DP		None	Wanapum, Pr. Rpds., WA	SS			
16	Grant Co. PUD #2 (4)	FP		None	Wanapum, Pr. Rpds., WA	SS			
17	Douglas Co. PUD	DP		None	Wells, WA	SS			
18	Douglas Co. PUD	FP		None	Wells, WA	SS			
19	Tacoma City Light	DP		None	Priest Rapids, WA	NA			
20	Tacoma City Light	FP		None	Priest Rapids, WA	NA			
21	B.C. Hydro	DP		None	Priest Rapids, WA	NA			
22	B.C. Hydro	FP		None	Priest Rapids, WA	NA			
23	Bonneville Pwr. Adm.	DP		None	Various	RS-SS			
24	Bonneville Pwr. Adm. (1)	FP		None	Various	RS-SS			
25	Pend Oreille Co. PUD	FP		None	Colville, WA	SS			
26	Arizona Pub. Serv. (8)	FP		84	Hot Springs, MT	RS			
27	Cowlitz Co. PUD	DP		None	Rocky Reach, WA	NA			
28	Colockum PUD	DP		None	Rocky Reach, WA	NA			
29	Total								
30	OTHER NONUTILITIES								
31	Vaagen Lumber (5)	FP		None	Note (5)	SS			
32	Potlatch Corp. (5)	FP		None	Note (5)	RS			
33	Phillips Ranch (5)	O		None	Note (5)	NA			
34	Ernest Lindquist (5)	O		None	Note (5)	NA			
35	Plummer-Wood Prod. Inc.	DP		None	Note (5)	RS			
36	Total								
37	TOTAL PURCHASED POWER								
38									
39	Notes: (1) Settlement based on scheduled transactions.								
40	(2) Contract amount not segregable as to demand and energy charge.								
41	(3) Settlement based on total plant cost.								
42	(4) Settlement based on Respondent's allocation of total palnt cost.								
43	(5) Cogeneration purchased within Respondent's elec. control area.								
44	(6) Centralia coal pile transfer settlement.								
45									

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
The Washington Water Power Company	(1) [X] An Original (2) [ ] A Resubmission	April 30, 1984	Dec. 31, 19 83

PURCHASED POWER (Account 555) (Continued)
(Except interchange power)

from the same company.

4. If receipt of power is at a substation, indicate ownership in column (f), using the following codes: RS, respondent owned or leased; SS, seller owned or leased.

5. If a fixed number of megawatts of maximum demand is specified in the power contract as a basis of billing, enter this number in column (g). Base the number of megawatts of maximum demand shown in columns (h) and (i) on actual monthly readings. Furnish those figures whether they are used or not in the determination of demand charges. Show in column (j) type of demand reading (i.e. instantaneous, 15, 30, or 60 minutes integrated).

6. For column (l) enter the number of megawatt hours purchased as shown by the power bills rendered to the purchases.

7. Explain in a footnote any amount entered in column (o), such as fuel or other adjustments.

Type of Demand Reading (j) (7)	Voltage at Which Received (k)	Megawatt Hours (l)	Cost Of Energy: Demand Charges (m)	Cost Of Energy: Energy Charges (n)	Cost Of Energy: Other Charges (o)	Cost Of Energy: Total (m+n+o) (p)	Line No.
							1
	230 Kv	1,440		12,600		12,600	2
	230 Kv	213,332		832,995		832,995	3
	230 Kv	12		184,260		184,260	4
	110-230 Kv	66,000		1,538,687		1,538,687	5
	110-230 Kv	66,877		1,560,426		1,560,426	6
	230 Kv	86,433		1,811,597		1,811,597	7
	500 Kv	6,260		172,526		172,526	8
	230 Kv	4,308		94,992		94,992	9
		444,662		6,208,083		6,208,083	10
							11
	110 Kv	25,360		180,846		180,846	12
	110 Kv	407,876		1,615,811		1,615,811	13
	110 Kv	194,239		688,466		688,466	14
	230 Kv	14,438		165,869		165,869	15
	230 Kv	726,279	770,000	2,241,960		3,011,960	16
	230 Kv	10,744		263,362		263,362	17
	230 Kv	182,914		834,238		834,238	18
	230 Kv	7,087		47,744		47,744	19
	230 Kv		117,500			117,500	20
	230 Kv	21,810		276,940		276,940	21
	230 Kv	349,860		5,636,700		5,636,700	22
	110-230 Kv	551,584		3,550,609		3,550,609	23
	110-230 Kv	1,132,921	191,058	22,696,574		22,887,632	24
	115 Kv	24,956		179,220		179,220	25
	230 Kv	106,260		4,873,189		4,873,189	26
	230 Kv	300		4,200		4,200	27
	230 Kv	34,460		132,175		132,175	28
		3,791,088	1,078,558	43,387,903		44,466,461	29
							30
	13 Kv			1,108,254		1,108,254	31
	13 Kv			72,432		72,432	32
	13 Kv			2,403		2,403	33
	13 Kv			162		162	34
	13 Kv			9,720		9,720	35
				1,192,971		1,192,971	36
		4,235,750	1,078,558	50,788,957		51,867,515	37
							38

Notes: (7) Col. (g): None; Col. (h), (i), (j): Not available.

(8) Purchased 106,260 Mwh of electricity from Arizona Public Service who delivered it to Southern California Edison for the Respondent.

Attachment 5-4
Forecasts and Backcasts of Average System Costs and Loads for FY 2002 Through 2008
WP-07-E-BPA-83

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
The Washington Water Power Company	(1) [X] An Original (2) [ ] A Resubmission	April 30, 1984	Dec. 31, 1983

SUMMARY OF INTERCHANGE ACCORDING TO COMPANIES AND POINTS OF INTERCHANGE
(Included in Account 555)

1. Report below all of the megawatt-hours received and delivered during the year. For receipts and deliveries under interchange power agreements, show the net charge or credit resulting therefrom.

2. Provide subheadings and classify interchanges as to (1) Associated Utilities, (2) Nonassociated Utilities, (3) Associated Nonutilities, (4) Other Nonutilities, (5) Municipalities, (6) Cooperatives, and (7) Other Public Authorities. For each interchange across a state line place an "x" in column (b).

3 Furnish particulars (details) of settlements for interchange power in a footnote or on a supplemental page; include the name of each company, the nature of the transaction, and the dollar amounts involved. If settlement for any transaction also includes credit or debit amounts other than for increment generation expenses, show such other component amounts separately, in addition to debit or credit for increment generation expenses, and give a brief explanation of the factors and principles under which such other component amounts were determined. If such settlement represents the net of debits and credits under an interconnection, power pooling, coordination, or other such arrangement, submit a copy of the annual summary of transactions and billings among the parties to the agreement. If the amount of settlement reported in this schedule for any transaction does not represent all of the charges and credits covered by the agreement, furnish in a footnote a description of the other debits and credits and state the amounts and accounts in which such other amounts are included for the year.

Line No.	Name of Company (a)	Interchanges Across State Lines (b)	FERC Rate Schedule Number (c)	Point of Interchange (d)	Voltage at Which Interchanged (e)	Megawatt Hours: Received (f)	Megawatt Hours: Delivered (g)	Megawatt Hours: Net Difference (h)	Amount of Settlement (i)
1	Schedule attached - Page 328-A - Interchange Power Summary of The Washington Water Power Company.								
2									
3									
4									
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Next Page is 332

THE WASHINGTON WATER POWER COMPANY
INTERCHANGE POWER (ACCOUNT 555)
Page 328-A
Year Ended December 31, 1983

Name of Company (a)	FERC Rate Schedule Number (c)	Interchange Voltage (Kv) (e)	Interchange (1) Received (Megawatt-Hours) (f)	Interchange (1) Delivered (Megawatt-Hours) (g)	Net Transactions (Megawatt-Hours) (h)	Net Transactions Settlement (i)
Associated Utilities						
The Washington Water Power Company (2)		110-230	(150)		(150)	
" " " " " (3)		110-230	55		55	
Total			(95)		(95)	
Nonassociated Utilities						
Idaho Power Company	87.1	110-230	768,341	706,749	61,592	
Pacific Power & Light Company	87.1	60-230	194,008	186,375	7,633	4,227
Portland General Electric Company	87.1	60-230	6,182	106,975	(100,793)	
Puget Sound Power & Light Company	87.1	110	31,690	24,284	7,406	
Montana Power Company	87.1	110-230	134,535	126,481	8,054	825
Southern California Edison	88,144 & 123	110-230				(10,320)
San Diego Gas & Electric	64 & 88	110-230	746,061	466,061	280,000	(1,500)
Utah Power & Light Company	87.1	110-230	5,385	22,420	(17,035)	
Sierra Pacific Power Company	87.1		316		316	
Total			1,886,518	1,639,345	247,173	(6,768)
Municipalities						
City of Seattle	N/A	110-230	4,370	4,320	50	
City of Spokane	N/A	13	19,527		19,527	
City of Tacoma	N/A	230	1,027	1,147	(120)	
Total			24,924	5,467	19,457	
Other Public Authorities						
Bonneville Power Administration	97	110-230	1,367,584	1,370,700	(3,116)	10,967
Chelan Co. PUD No. 1 - Rocky Reach	N/A	110	35,999	8,640	27,359	
Grant Co. PUD No. 2	N/A	230	102,984	114,604	(11,620)	
Douglas Co. PUD No. 1	N/A	110-230	10,178	11,942	(1,764)	
Cowlitz Co. PUD No. 1	N/A	110-230	1,200	641	559	
Total			1,517,945	1,506,527	11,418	10,967
Other Nonutilities						
Vaagen Lumber Co. (4)	N/A	13	27,850		27,850	
Potlatch Corporation (4)	N/A	13	3,018		3,018	
Phillips Ranch (4)	N/A	13	89		89	
Ernest Lindquist (4)	N/A	13	6		6	
Plummer-Wood Prod. Inc. (4)	N/A	13	360		360	
Total			31,323		31,323	
TOTAL INTERCHANGE POWER			3,460,615	3,151,339	309,276	4,199

( ) Red Figures

Notes: (1) All interchanges are made at various points within state boundaries.

(2) These amounts represent minor hourly deviations.

(3) Receipts or deliveries other than billing transactions.

(4) Cogeneration purchased within respondent's electrical control area.

Name of Respondent	This Report Is:	Date of Report	Year of Report
The Washington Water Power Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr) April 30, 1984	Dec. 31, 19 83

TRANSMISSION OF ELECTRICITY FOR OR BY OTHERS (Accounts 456 and 565)
(Including transactions sometimes referred to as "wheeling")

1. Describe below and give particulars of any transactions by respondent during the year for transmission of electricity for or by others during year, including transactions sometimes referred to as wheeling.

2. Provide separate subheadings for: (a) *Transmission of Electricity for Others* (included in Account 456) and (b) *Transmission of Electricity by Others* (Account 565).

3. Furnish the following information in the space below concerning each transaction:
   - (a) Name of company and description of service rendered or received. Designate associated companies.
   - (b) Points of origin and termination of service specifying also any transformation service involved.
   - (c) MWh received and MWh delivered.
   - (d) Monetary settlement received or paid and basis of settlement, included in Account 456 or 565.
   - (e) Nonmonetary settlement, if any, specifying the MWh representing compensation for the service, specifying whether such power was firm power, dump or other power, and state basis of settlement. If nonmonetary settlement was other than MWh describe the nature of such settlement and basis of determination.
   - (f) Other explanations which may be necessary to indicate the nature of the reported transactions. Include in such explanations a statement of any material services remaining to be received or furnished at end of year and the accounting recorded to avoid a possible material distortion of reported operating income for the year.

Acct. 456, Transmission of Electricity for Others

1. 3(a) Bonneville Power Administration
   Use of facilities--Borderline loads
   (b) Washington-Idaho
   (c) None
   (d) (Note 2)
   (e) $630,062 (Note 2)

2. 3(a) Idaho Power Company
   Transmission and use of facilities
   (b) Idaho-Washington-Utah
   (c) 82,810 Mwh
   (d) $62,108

3. 3(a) The Montana Power Company
   Transmission and use of facilities
   (b) Montana-Washington
   (c) 1,624 Mwh
   (d) $1,208

4. 3(a) Pacific Power & Light Company
   Transmission and use of facilities--Sandpoint
   (b) Idaho
   (c) None
   (d) $41,961 (Based on demand)

5. 3(a) Portland General Electric Company
   Transmission and use of facilities
   (b) Idaho-Washington-Montana-Utah
   (c) 103,483 Mwh
   (d) $52,919

6. 3(a) Puget Sound Power & Light Company
   Transmission and use of facilities--Colstrip power
   (b) Montana-Washington
   (c) 34,432 Mwh
   (d) $25.824 (See (c) above); $736,776 (Note 1)

Acct. 456, Transmission of Electricity for Others (contd.)

7. 3(a) Puget Sound Power & Light Company
Transmission and use of facilities--Secondary
(b) Montana-Utah-Washington-Idaho
(c) 14,028 Mwh
(d) $10,116

8. 3(a) Seattle City Light
Transmission and use of facilities
(b) Washington
(c) 18,797 Mwh
(d) $18,233

9. 3(a) Sierra Pacific Power Company
Transmission and use of facilities
(b) Washington-Idaho
(c) 8,157 Mwh
(d) $3,138

10. 3(a) Utah Power & Light Company
Transmission and use of facilities
(b) Utah-Washington-Idaho-Montana
(c) 134,352 Mwh
(d) $85,630

11. 3(a) Chelan County Public Utility District
Load factoring service
(b) Washington
(c) 3,040 Mwh
(d) $5,810

12. 3(a) Douglas County Public Utility District
Load factoring service
(b) Washington
(c) 2,210 Mwh
(d) $3,198

13. 3(a) Pacific Power & Light Company
Load factoring service
(b) Washington
(c) 400 Mwh
(d) $400

14. 3(a) Utah Power & Light Company
Load factoring service
(b) Idaho-Washington
(c) 100 Mwh
(d) $300

Acct. 565, Transmission of Electricity by Others

1. 3(a) Bonneville Power Administration
Transmission and use of facilities-- British Columbia Hydro and Power Authority Firm Power
(b) Washington
(c) 349,860 Mwh (Note 1)
(d) $172,200 (Note 1)

2. 3(a) Bonneville Power Administration
Transmission and use of facilities--Colstrip
(b) Montana-Washington
(c) None
(d) $416,354 (Note 1)

3. 3(a) Bonneville Power Administration
Transmission and use of facilities--Colstrip-Centralia
(b) Montana-Washington
(c) None
(d) $674,580 (Note 1)

4. 3(a) Bonneville Power Administration
Transmission and use of facilities--Columbia Storage Power Exchange
(b) Washington
(c) 213,332 Mwh
(d) $91,569

5. 3(a) Bonneville Power Administration
Transmission and use of facilities--Entitlement and Supplemental Capacity
(b) Washington
(c) 837 Mwh (Net deliveries) (Note 1)
(d) $26,059 (Note 1)

6. 3(a) Bonneville Power Administration
Transmission and use of facilities--Hanford Extension
(b) Washington
(c) 387,241 Mwh (Note 1)
(d) $82,838 (Note 1)

7. 3(a) Bonneville Power Administration
Transmission and use of facilities--Hanford-Industry
(b) Washington
(c) 350,479 Mwh (Note 1)
(d) $61,026 (Note 1)

8. 3(a) Bonneville Power Administration
Transmission and use of facilities--Kettle Falls
(b) Washington
(c) 14,037 Mwh
(d) $13,616

9. 3(a) Bonneville Power Administration
Transmission and use of facilities--Northwest
(b) Washington
(c) 56,867 Mwh
(d) $55,161

Acct. 565, Transmission of Electricity by Others (contd.)

10. 3(a) Bonneville Power Administration
Transmission and use of facilities--Pend Oreille
(b) Washington
(c) 21,980 Mwh (Note 1)
(d) $7,330 (Note 1)

11. 3(a) Bonneville Power Administration
Transmission and use of facilities--San Diego Gas & Electric Company
(b) Washington-California
(c) 60,306 Mwh (Note 2)
(d) $568,512 (Note 1)
(e) Mwh in (c) above: $(150,764): Dump: (Note 2)

12. 3(a) Bonneville Power Administration
Transmission and use of facilities--Secondary
(b) Washington
(c) 400,348 Mwh (Note 2)
(d) (Note 2)
(e) Mwh in (c) above: $1,000,869: Dump: (Note 2)

13. 3(a) Bonneville Power Administration
Transmission and use of facilities--Southern California Edison Company
(b) Washington-California
(c) 69,840 Mwh (Note 1)
(d) $459,540 (Note 1)

14. 3(a) Idaho Power Company
Transmission and use of facilities
(b) Idaho-Washington
(c) 4,308 Mwh
(d) $3,231

15. 3(a) The Montana Power Company
Transmission and use of facilities
(b) Idaho-Washington
(c) 621 Mwh
(d) $188

16. 3(a) Puget Sound Power & Light Company
Transmission and use of facilities--Secondary
(b) Washington
(c) 3,613 Mwh
(d) $2,710

17. 3(a) Western Area Power Administration
Transmission of Arizona Public Service Company Firm Power
(b) Arizona-Washington
(c) None
(d) $88,000 (Note 1)

Notes (1): Dollars are ircluded which are established by firm contract and are independent from megawatt-hours.

(2): Settlement is made through Bonneville Power Administration Exchange Account (Contract No. 14-03-29242). Dollars shown are calculated; but no monetary exchange occurs in these transactions.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
The Washington Water Power Company	(1) [X] An Original (2) [ ] A Resubmission	April 30, 1984	Dec. 31, 1983

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)			Amount (b)
1	Industry Association Dues			286,733
2	Nuclear Power Research Expenses			-0-
3	Other Experimental and General Research Expenses			1,168,845
4	Publishing and Distributing Information and Reports to Stockholders; Trustee, Registrar, and Transfer Agent Fees and Expenses, and Other Expenses of Servicing Outstanding Securities of the Respondent			556,364
5	Other Expenses *(List items of $5,000 or more in this column showing the (1) purpose, (2) recipient and (3) amount of such items. Group amounts of less than $5,000 by classes if the number of items so grouped is shown)*			
6				
7	Directors Fees and Expenses	Fees	Expenses	
8	Rodney G. Aller	5,374	2,996	8,370
9	Edward W. Kiemle	5,693	-0-	5,693
10	Duane B. Hagadone	5,655	-0-	5,655
11	James B. McMonigle	6,207	1,350	7,557
12	James A. Poore, Jr.	6,547	1,817	8,364
13	Margaret C. Ross	5,715	1,807	7,522
14	Eugene Thompson	6,963	893	7,856
15				
16	Publicity - Services and Subscriptions			
17	Labor			23,572
18	17 Items under $5,000			2,837
19				
20	Publicity - Special Services, Motion Pictures, Tours			
21	Labor			27,537
22	92 Items under $5,000			27,756
23				
24	Publicity - Information and Employees' Education			
25	Labor			78,995
26	107 Items under $5,000			18,043
27	Litho Art Printers			5,022
28				
29	Other Miscellaneous General Expenses			
30	17 Items under $5,000			995
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				
43				
44				
45				
46	TOTAL			2,247,716

Attachment 5-4
Forecasts and Backcasts of Average System Costs and Loads for FY 2002 Through 2008
WP-07-E-BPA-83
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
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DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Accounts 403, 404, 405)
(Except amortization of acquisition adjustments)

1. Report in Section A for the year the amounts for: (a) *Depreciation Expense* (Account 403); (b) *Amortization of Limited-Term Electric Plant* (Account 404); and (c) *Amortization of Other Electric Plant* (Account 405).

2. Report in section B the rates used to compute amortization charges for electric plant (Accounts 404 and 405). State the basis used to compute the charges and whether any changes have been made in the basis or rates used from the preceding report year.

3. Report all available information called for in section C every fifth year beginning with report year 1971, reporting annually only changes to columns (c) through (g) from the complete report of the preceding year.

Unless composite depreciation accounting for total depreciable plant is followed, list numerically in column (a) each plant subaccount, account or functional classification, as appropriate, to which a rate is applied. Identify at the bottom of section C the type of plant included in any subaccounts used.

In column (b) report all depreciable plant balances to which rates are applied showing subtotals by functional classifications and showing a composite total. Indicate at the bottom of section C the manner in which column (b) balances are obtained. If average balances, state the method of averaging used.

For columns (c), (d), and (e) report available information for each plant subaccount, account or functional classification listed in column (a). If plant mortality studies are prepared to assist in estimating average service lives, show in column (f) the type mortality curve selected as most appropriate for the account and in column (g), if available, the weighted average remaining life of surviving plant.

If composite depreciation accounting is used, report available information called for in columns (b) through (g) on this basis.

4. If provisions for depreciation were made during the year in addition to depreciation provided by application of reported rates, state at the bottom of section C the amounts and nature of the provisions and the plant items to which related.

A. Summary of Depreciation and Amortization Charges

Line No.	Functional Classification (a)	Depreciation Expense (Account 403) (b)	Amortization of Limited-Term Electric Plant (Acct. 404) (c)	Amortization of Other Electric Plant (Acct. 405) (d)	Total (e)
1	Intangible Plant				
2	Steam Production Plant	1,668,885			1,668,885
3	Nuclear Production Plant				
4	Hydraulic Production Plant—Conventional	1,230,288	4,197		1,234,485
5	Hydraulic Production Plant—Pumped Storage				
6	Other Production Plant	522,782			522,782
7	Transmission Plant	2,234,374			2,234,374
8	Distribution Plant	6,789,895			6,789,895
9	General Plant	1,302,043			1,302,043
10	Common Plant—Electric				
11	TOTAL	13,748,267	4,197		13,752,464

B. Basis for Amortization Charges

Amortization of Limited-Term Electric Plant - Account 404

Amortization of limited-term electric plant is based upon the operating portion of the Noxon Rapids Licensed Project No. 2075 which ends May 1, 2005.

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DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In thousands) (b) (1)	Estimated Avg. Service Life (c) (2)	Net Salvage (Percent) (d) (2)	Applied Depr. Rate(s) (Percent) (e) (2)	Mortality Curve Type (f) (2)	Average Remaining Life (g)
12	STEAM PRODUCTION PLANT						
13	Centralia Plant (3)						
14	311	5,551					
15	312	29,742					
16	314	7,634					
17	315	2,819					
18	316	509					
19	Total	46,255					
20							
21							
22	Kettle Falls (7)						
23	311	20,145					
24	312	41,160					
25	314	13,952					
26	315	8,974					
27	316	1,895					
28	Total	86,126 (7)					
29							
30	Total Steam						
31	Production	132,381					
32							
33							
34	HYDRAULIC PRODUCTION PLANT (4)						
35	Cabinet Gorge						
36	330 (5)	7,006					
37	331	7,554					
38	332	16,206					
39	333	8,933					
40	334	1,085					
41	335	1,062					
42	336	821					
43	Total	42,667					
44							
45							
46	Noxon Rapids						
47	330 (5)	29,424					
48	331	8,991					
49	332	28,837					
50	333	27,528					
51	334	1,713					
52	335	1,099					
53	336	89					
54	Total	97,681					
55							
56							
57							
58							
59							
60							
61							
62							
63							

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DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges (Continued)

Line No.	Account No. (a)	Depreciable Plant Base (In thousands) (b) (1)	Estimated Avg. Service Life (c) (2)	Net Salvage (Percent) (d) (2)	Applied Depr. Rate(s) (Percent) (e) (2)	Mortality Curve Type (f) (2)	Average Remaining Life (g)
64	Post Falls						
65	330 (5)	757					
66	331	322					
67	332	1,182					
68	333	1,763					
69	334	376					
70	335	8					
71	Total	4,408					
72							
73							
74	Long Lake						
75	330 (5)	418					
76	331	1,075					
77	332	3,556					
78	333	1,814					
79	334	802					
80	335	55					
81	Total	7,720					
82							
83							
84	Little Falls						
85	330 (5)	17					
86	331	553					
87	332	752					
88	333	1,287	(6)				
89	334	846					
90	335	33					
91	Total	3,488					
92							
93							
94	Upper Falls						
95	330 (5)	64					
96	331	367					
97	332	717					
98	333	449	(6)				
99	334	77	(6)				
100	335	2					
101	Total	1,676					
102							
103							
104	Nine Mile						
105	330 (5)	4					
106	331	314					
107	332	1,027					
108	333	564					
109	334	176					
110	335	15					
111	Total	2,100					
112							
113							
114							
115							

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DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges (Continued)

Line No.	Account No. (a)	Depreciable Plant Base (In thousands) (b) (1)	Estimated Avg. Service Life (c) (2)	Net Salvage (Percent) (d) (2)	Applied Depr. Rate(s) (Percent) (e) (2)	Mortality Curve Type (f) (2)	Average Remaining Life (g)
116	Meyers Falls						
117	330 (5)	24					
118	331	47					
119	332	215					
120	333	75 (6)					
121	334	14 (6)					
122	335	1 (6)					
123	Total	376					
124							
125							
126	Monroe Street						
127	331	423					
128	332	2,776					
129	333	407 (5)					
130	334	37					
131	335	6 (6)					
132	336	2					
133	Total	3,651					
134							
135	Total Hydro						
136	Production	163,767					
137							
138							
139	OTHER PRODUCTION PLANT						
140	Othello Turbine						
141	341	314					
142	342	133					
143	343	1,280					
144	344	323					
145	345	117					
146	346	102					
147	Total	2,269					
148							
149							
150	Northeast Turbine						
151	341	246					
152	342	1,139					
153	343	6,448					
154	344	2,595					
155	345	54					
156	346	226					
157	Total	10,708					
158							
159	Total Other						
160	Production	12,977					
161							
162							
163							
164							
165							
166							

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
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DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges (Continued)

Line No	Account No (a)	Depreciable Plant Base (In thousands) (b) (1)	Estimated Avg Service Life (c) (2)	Net Salvage (Percent) (d) (2)	Applied Depr. Rate(s) (Percent) (e) (2)	Mortality Curve Type (f) (2)	Average Remaining Life (g)
167	TRANSMISSION PLANT						
168	350 (5)	4,367					
169	352	1,610					
170	353	45,564					
171	354	3,159					
172	355	22,203					
173	356	25,395					
174	357	373					
175	358	594					
176	359	53					
177	Total	103,318					
178							
179							
180	DISTRIBUTION PLANT						
181	361	4,157					
182	362	36,610					
183	364	54,027					
184	365	38,129					
185	366	5,294					
186	367	17,890					
187	368	51,052					
188	369	24,566					
189	370	10,368					
190	373	7,145					
191	Total	249,238					
192							
193							
194	GENERAL PLANT						
195	389 (5)	86					
196	390	21,186					
197	391	2,468					
198	391.1	3,828					
199	393	229					
[illegible]	394	1,173					
[illegible]	395	519					
202	397	3,760					
203	398	138					
204	Total	33,387					
205							
206	Total						
207	Company	695,068					
208							
209							
210	Notes: (1)	Depreciable plant base is average beginning and end of year balances at original plant					
211		cost, excluding Land in Fee, Intangible Plant, Leased Property, and Transportation and					
212		Power Operated Equipment (See Note 5).					
213							
214	(2)	Reference is made to Page 430 of the Company's Annual Report on Form 1 for the year					
215		ended December 31, 1979.					
216							
217	(3)	Company's 15% ownership in the Centralia Thermal Production Plant.					

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DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges (Continued)

Line No.	Account No. (a)	Depreciable Plant Base (In thousands) (b) (1)	Estimated Avg Service Life (c) (2)	Net Salvage (Percent) (d) (2)	Applied Depr. Rate(s) (Percent) (e) (2)	Mortality Curve Type (f) (2)	Average Remaining Life (g)
218	Notes: (4)	Hydraulic Production Plant subject to 5% present worth method of depreciation.					
219							
220	(5)	Land rights only.					
221							
222	(6)	Fully depreciated.					
223							
224	(7)	Balance December 31, 1983. Project in service December 1, 1983.					

Name of Respondent	This Report Is	Date of Report (Mo, Da, Yr)	Year of Report
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PARTICULARS CONCERNING CERTAIN INCOME DEDUCTIONS AND INTEREST CHARGES ACCOUNTS

Report the information specified below, in the order given, for the respective income deduction and interest charges accounts. Provide a subheading for each account and a total for the account. Additional columns may be added if deemed appropriate with respect to any account.

(a) *Miscellaneous Amortization* (Account 425)—Describe the nature of items included in this account, the contra account charged, the total of amortization charges for the year, and the period of amortization.

(b) *Miscellaneous Income Deductions*—Report the nature, payee, and amount of other income deductions for the year as required by Accounts 426.1, Donations; 426.2, Life Insurance; 426.3, Penalties; 426.4, Expenditures for Certain Civic, Political and Related Activities; and 426.5, Other Deductions, of the Uniform System of Accounts. Amounts of less than 5% of each account total for the year (or $1,000, whichever is greater) may be grouped by classes within the above accounts.

(c) *Interest on Debt to Associated Companies* (Account 430)—For each associated company to which interest on debt was incurred during the year, indicate the amount and interest rate respectively for (a) advances on notes, (b) advances on open account, (c) notes payable, (d) accounts payable, and (e) other debt, and total interest. Explain the nature of other debt on which interest was incurred during the year.

(d) *Other Interest Expense* (Account 431)—Report particulars (details) including the amount and interest rate for other interest charges incurred during the year.

Line No.	Item (a)	Amount (b)
1	Acct. 425 - Miscellaneous Amortization	None
2		
3	Acct. 426 Other Income Deductions (Donations 426.1)	
4	United Way of Spokane County	60,500
5	United Way - Various	2,304
6	Total United Way	62,804
7	Catholic Charities - Project Share	43,000
8	Spokane Club	10,859
9	Washington State University	10,783
10	341 Items under $10,832 each	89,191
11	Total	216,647
12		
13	426.2 - Life Insurance	None
14		
15	426.3 Penalties	
16	State of Montana	5
17	Department of Labor	300
18	Total	305
19		
20	426.4 - Expenditures for Certain Civic, Political and Related Activities	
21	Michael Hicks, Company Employee - Labor & Expenses	32,619
22	Fair Competition Council	9,000
23	Thomas Paine, Company Employee Labor & Expenses	50,864
24	35 items under $6,228 each	32,090
25	Total	124,563
26		
27	426.5 - Other	
28	Architectural Services/Clarkston	22,526
29	Hellsell, Fetterman, Martin, Todd & Hokanson	16,027
30	Lane, Powell, Moss & Miller	6,855
31	Post Falls, ID Lawsuit	21,618
32	Write-off Abandon Properties	5,552
33	4 Items under $3,711 each	1,647
34	Total	74,225
35		
36	Total 426.1 - 426.5	415,740
37		
38		
39		
40		
41		

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PARTICULARS CONCERNING CERTAIN INCOME DEDUCTIONS AND INTEREST CHARGES ACCOUNTS

Report the information specified below, in the order given, for the respective income deduction and interest charges accounts. Provide a subheading for each account and a total for the account. Additional columns may be added if deemed appropriate with respect to any account.

(a) *Miscellaneous Amortization* (Account 425)—Describe the nature of items included in this account, the contra account charged, the total of amortization charges for the year, and the period of amortization.

(b) *Miscellaneous Income Deductions*—Report the nature, payee, and amount of other income deductions for the year as required by Accounts 426.1, Donations; 426.2, Life Insurance; 426.3, Penalties; 426.4, Expenditures for Certain Civic, Political and Related Activities; and 426.5, Other Deductions, of the Uniform System of Accounts. Amounts of less than 5% of each account total for the year (or $1,000, whichever is greater) may be grouped by classes within the above accounts.

(c) *Interest on Debt to Associated Companies* (Account 430)—For each associated company to which interest on debt was incurred during the year, indicate the amount and interest rate respectively for (a) advances on notes, (b) advances on open account, (c) notes payable, (d) accounts payable, and (e) other debt, and total interest. Explain the nature of other debt on which interest was incurred during the year.

(d) *Other Interest Expense* (Account 431)—Report particulars (details) including the amount and interest rate for other interest charges incurred during the year.

Item (a)	Interest Rates	Amount (b)
Acct. 430 - Interest on Debt to Associated Companies - Notes Payable		
Washington Irrigation & Development Company	Various (1)	3,350
Spokane Industrial Park, Inc.	" (1)	195,982
Development Associates, Inc.	" (1)	38,897
The Limestone Company, Inc.	" (1)	1,014
Water Power Improvement Company	" (1)	0
WP Energy Co.	" (2)	2,635
Empire Energy Co.	(1)	249
Total		242,127
Acct. 431 - Other Interest Expense	Interest Rates	
Interest on BPA Residential Exchange	Various	(462)
Interest on Customers' Deposits	"	21,137
Interest on Late Tax Payments	"	1,586,484
Interest to Montana Power Company - Colstrip	"	5,128
Interest on Late BPA Payments	"	2,924
Interest due Customers on Northwest Pipeline Refund	"	63,030
Interest on Other Items	"	3,837
Total		1,682,078

Notes: (1) Based on the one-month certificate of deposit rate in effect on the first business day of the month.

(2) Based on the DMM-Bid Rate as determined by Citibank.

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REGULATORY COMMISSION EXPENSES

1. Report particulars (details) of regulatory commission expenses incurred during the current year (or incurred in previous years, if being amortized) relating to formal cases before a regulatory body, or cases in which such a body was a party.

2. In columns (b) and (c), indicate whether the expenses were assessed by a regulatory body or were otherwise incurred by the utility.

Line No.	Description (Furnish name of regulatory commission or body, the docket or case number, and a description of the case.) (a)	Assessed by Regulatory Commission (b)	Expenses of Utility (c)	Total Expenses to Date (d)	Deferred in Account 186 at Beginning of Year (e)
1	Federal Energy Regulatory Commission				
2	Docket No. ER 83-223-000 Relative to Wholesale				
3	Rates		1,357	1,357	
4	Docket No. ER 84-208-000 Relative to Wholesale				
5	Rates				
6	Docket No. RP-81-47 Relative to N.W. Pipeline		33,043	33,043	
7	Docket No. RP-82-56-00 Relative to N.W. Pipeline		76,815	76,815	
8					
9	Idaho Public Utilities Commission				
10	Case No. P-300 Relative to Generic Hearings		32	32	
11					
12	Electric and Gas General Rate Case Hearings with				
13	Costs Common to the State of Washington and/or				
14	Idaho				
15	Washington Cause No. U-82-10 and 11;				
16	Idaho Case No. U-1008-170 and 171	213,096	16,368	229,464	
17					
18	Washington Cause No. U-83-26;				
19	Idaho Case No. U-1008-185		561,668	561,668	
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL	213,096	689,283	902,379	

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REGULATORY COMMISSION EXPENSES (Continued)

3. Show in column (k) any expenses incurred in prior years which are being amortized. List in column (a) the period of amortization.

4. The totals of columns (e), (i), (k), and (l) must agree with the totals shown at the bottom of page 223 for Account 186.

5. List in column (f), (g), and (h) expenses incurred during year which were charged currently to income, plant, or other accounts.

6. Minor items (less than $25,000) may be grouped.

EXPENSES INCURRED DURING YEAR				AMORTIZED DURING YEAR			
CHARGED CURRENTLY TO							
Department (f)	Account No. (g)	Amount (h)	Deferred to Account 186 (i)	Contra Account (j)	Amount (k)	Deferred in Account 186, End of Year (l)	Line No.
							1
							2
Electric	928	1,333				24	3
							4
							5
Gas	1928	33,043					6
Gas	1928	76,815					7
							8
							9
Electric	928	32					10
							11
							12
							13
							14
							15
Electric	928	189,530					16
Gas	1928	39,934					17
							18
Electric	928	552,355					19
Gas	1928	9,313					20
							21
							22
							23
							24
							25
							26
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							40
							41
							42
							43
							44
							45
		902,355				24	46

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RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES

1. Describe and show below costs incurred and accounts charged during the year for technological research, development, and demonstration (R, D & D) projects initiated, continued, or concluded during the year. Report also support given to others during the year for jointly-sponsored projects. (Identify recipient regardless of affiliation.) For any R, D & D work carried on by the respondent in which there is a sharing of costs with others, show separately the respondent's cost for the year and cost chargeable to others. (See definition of research, development, and demonstration in Uniform System of Accounts.)

2. Indicate in column (a) the applicable classification, as shown below. Classifications:

A. Electric R, D & D Performed Internally
- (1) Generation
  - a. Hydroelectric
    - i. Recreation, fish, and wildlife
    - ii. Other hydroelectric
  - b. Fossil-fuel steam
  - c. Internal combustion or gas turbine
  - d. Nuclear
  - e. Unconventional generation
  - f. Siting and heat rejection
- (2) System Planning, Engineering and Operation
- (3) Transmission
  - a. Overhead
  - b. Underground
- (4) Distribution
- (5) Environment (other than equipment)
- (6) Other *(Classify and include items in excess of $5,000.)*
- (7) Total Cost Incurred

B. Electric R, D & D Performed Externally
- (1) Research Support to the Electrical Research Council or the Electric Power Research Institute

Line No.	Classification (a)	Description (b)
1	B(2)	EPRI Program for Improving Electric Power Production, Distribution and
2		Utilization
3		
4	B(4)	Electric Rate Price Elasticity
5		
6	B(4)	Economic Plans for Industrial Development
7		
8	A(1)e, B(4)	Research Support - Natural Gas Fuel Cell
9		
10	A(6), B(4)	Solar Energy Study
11		
12	A(6)	Heat Pump Study
13		
14	A(1)e	Mill Waste and Forest Residuals Study - Orofino/Grangeville - Chase
15		Associates
16		
17	A(1)e	Municipal Refuse Study
18		
19	A(6)	Electric Vehicle Feasibility Study
20		
21	A(5), B(4)	Air Quality Study
22		
23	B(4)	Analysis of Ungaged Streams
24		
25	A(6), B(4)	Other R&D Activities
26		
27		Total
28		
29		
30		
31		
32		
33		
34		
35		
36		
37		
38		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
The Washington Water Power Company	(1) [X] An Original (2) [ ] A Resubmission	April 30, 1984	Dec. 31, 19 83

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES (Continued)

(2) Research Support to Edison Electric Institute
(3) Research Support to Nuclear Power Groups
(4) Research Support to Others *(Classify)*
(5) Total Cost Incurred

3. Include in column (c) all R, D & D items performed internally and in column (d) those items performed outside the company costing $5,000 or more, briefly describing the specific area of R, D & D (such as safety, corrosion control, pollution, automation, measurement, insulation, type of appliance, etc.). Group items under $5,000 by classifications and indicate the number of items grouped. Under Other, (A.(6) and B.(4)) classify items by type of R, D & D activity.

4. Show in column (e) the account number charged with expenses during the year or the account to which amounts were capitalized during the year, listing Account 107, *Construction Work in Progress*, first. Show in column (f) the amounts related to the account charged in column (e).

5. Show in column (g) the total unamortized accumulation of costs of projects. This total must equal the balance in Account 188, *Research, Development, and Demonstration Expenditures*, outstanding at the end of the year.

6. If costs have not been segregated for R, D & D activities or projects, submit estimates for columns (c), (d), and (f) with such amounts identified by "Est."

7. Report separately research and related testing facilities operated by the respondent.

Costs Incurred Internally Current Year *(c)*	Costs Incurred Externally Current Year *(d)*	AMOUNTS CHARGED IN CURRENT YEAR Account *(e)*	Amount *(f)*	Unamortized Accumulation *(g)*	Line No.
					1
-0-	972,960	930	972,960		2
					3
-0-	13,740	930	13,740		4
					5
-0-	6,600	930	6,600		6
					7
313	4,652	930	4,965		8
					9
28,217	70,856	930	99,073		10
					11
4,994	-0-	930	4,994		12
					13
					14
310	-0-	930	310		15
					16
10,116	-0-	930	10,116		17
					18
145	-0-	930	145		19
					20
2,630	11,010	930	13,640		21
					22
-0-	30,618	930	30,618		23
					24
10,383	1,300	930	11,683		25
					26
57,108	1,111,736		1,168,844		27
					28
					29
					30
					31
					32
					33
					34
					35
					36
					37
					38

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
The Washington Water Power Company	(1) [X] An Original (2) [ ] A Resubmission	April 30, 1984	Dec. 31, 19 83

DISTRIBUTION OF SALARIES AND WAGES

Report below the distribution of total salaries and wages for the year. Segregate amounts originally charged to clearing accounts to *Utility Departments, Construction, Plant Removals, and Other Accounts*, and enter such amounts in the appropriate lines and columns provided. In determining this segregation of salaries and wages originally charged to clearing accounts, a method of approximation giving substantially correct results may be used.

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll Charged for Clearing Accounts (c)	Total (d)
1	Electric			
2	Operation			
3	Production	2,751,624		
4	Transmission	630,328		
5	Distribution	2,464,287		
6	Customer Accounts	3,982,136		
7	Customer Service and Informational	1,533,093		
8	Sales	104,830		
9	Administrative and General	4,509,799		
10	TOTAL Operation *(Enter Total of lines 3 thru 9)*	15,976,097		
11	Maintenance			
12	Production	607,306		
13	Transmission	338,689		
14	Distribution	2,220,830		
15	Administrative and General	359,285		
16	TOTAL Maintenance *(Enter Total of lines 12 thru 15)*	3,526,110		
17	Total Operation and Maintenance			
18	Production *(Enter Total of lines 3 and 12)*	3,358,930		
19	Transmission *(Enter Total of lines 4 and 13)*	969,017		
20	Distribution *(Enter Total of lines 5 and 14)*	4,685,117		
21	Customer Accounts *(Transcribe from line 6)*	3,982,136		
22	Customer Service and Informational *(Transcribe from line 7)*	1,533,093		
23	Sales *(Transcribe from line 8)*	104,830		
24	Administrative and General *(Enter Total of lines 9 and 15)*	4,869,084		
25	TOTAL Operation and Maintenance *(Total of lines 18 thru 24)*	19,502,207	619,922	20,122,129
26	Gas			
27	Operation			
28	Production—Manufactured Gas			
29	Production—Natural Gas (Including Expl. and Dev.)			
30	Other Gas Supply	106,315		
31	Storage, LNG Terminaling and Processing			
32	Transmission			
33	Distribution	803,927		
34	Customer Accounts	1,287,803		
35	Customer Service and Informational	242,110		
36	Sales	36,329		
37	Administrative and General	1,414,392		
38	TOTAL Operation *(Enter Total of lines 28 thru 37)*	3,890,876		
39	Maintenance			
40	Production—Manufactured Gas			
41	Production—Natural Gas			
42	Other Gas Supply			
43	Storage, LNG Terminaling and Processing			
44	Transmission			
45	Distribution	285,413		
46	Administrative and General	29,110		
47	TOTAL Maintenance *(Enter Total of lines 40 thru 46)*	314,523		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
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DISTRIBUTION OF SALARIES AND WAGES (Continued)

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll Charged for Clearing Accounts (c)	Total (d)
	Gas (Continued)			
48	Total Operation and Maintenance			
49	Production—Manufactured Gas *(Enter Total of lines 28 and 40)*			
50	Production—Natural Gas (Including Expl. and Dev.) *(Total of lines 29 and 41)*			
51	Other Gas Supply *(Enter Total of lines 30 and 42)*	106,315		
52	Storage, LNG Terminaling and Processing *(Total of lines 31 and 43)*			
53	Transmission *(Enter Total of lines 32 and 44)*			
54	Distribution *(Enter Total of lines 33 and 45)*	1,089,340		
55	Customer Accounts *(Transcribe from line 34)*	1,287,803		
56	Customer Service and Informational *(Transcribe from line 35)*	242,110		
57	Sales *(Transcribe from line 36)*	36,329		
58	Administrative and General *(Enter Total of lines 37 and 46)*	1,443,502		
59	TOTAL Operation and Maint. *(Total of lines 49 thru 58)*	4,205,399	132,522	4,337,921
60	**Other Utility Departments**			
61	Operation and Maintenance	336,183	3,817	340,000
62	TOTAL All Utility Dept. *(Total of lines 25, 59, and 61)*	24,043,789	756,261	24,800,050
63	**Utility Plant**			
64	Construction (By Utility Departments)			
65	Electric Plant	9,340,616	753,851	10,094,467
66	Gas Plant	701,980	41,074	743,054
67	Other	56,412	1,375	57,787
68	TOTAL Construction *(Enter Total of lines 65 thru 67)*	10,099,008	796,300	10,895,308
69	Plant Removal (By Utility Department)			
70	Electric Plant	540,249	16,333	556,582
71	Gas Plant	17,943	502	18,445
72	Other	14,730	151	14,881
73	TOTAL Plant Removal *(Enter Total of lines 70 thru 72)*	572,922	16,986	589,908
74	Other Accounts *(Specify)*:			
75	Unbilled Jobbing Work (174.1)			301,878
76	Miscellaneous Deferred Debits -			
77	Unadjusted Work Orders (186.2)			1,288,584
78	Cost and Expenses of Merchandising, Jobbing, and			
79	Contract Work (183)			172,408
80	Small Tool Expense (184)			60,702
81	Research and Development Expenditures (188)			47,934
82	Expenditures for Certain Civic, Political and			
83	Related Activities (426.4)			52,857
84	Other Deductions (426.5)			131
85	Other Expense (418.24)			131
86	Purchase and Stores Expenses (980)			26,062
87	Transportation Expenses (981)			17,489
88	Spokane Central Operating Facility			
89	Expenses (982)			3,695
90	Telephone Service Expenses (983.10)			954
91	Cafeteria Expenses-Labor (984.31)			58,723
92				
93				
94				
95	TOTAL Other Accounts	3,601,095	(1,569,547)	2,031,548
96	TOTAL SALARIES AND WAGES	38,316,814	-0-	38,316,814

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
The Washington Water Power Company	(1) [X] An Original (2) [ ] A Resubmission	April 30, 1984	Dec. 31, 1983

ELECTRIC ENERGY ACCOUNT

Report below the information called for concerning the disposition of electric energy generated, purchased, and interchanged during the year.

Line No.	Item (a)	Megawatt Hours (b)	Line No.	Item (a)	Megawatt Hours (b)
1	SOURCES OF ENERGY		20	DISPOSITION OF ENERGY	
2	Generation (Excluding Station Use):		21	Sales to Ultimate Consumers (Including Interdepartmental Sales)	5,970,446
3	Steam	1,083,629	22	Sales for Resale	3,006,924
4	Nuclear		23	Energy Furnished Without Charge	
5	Hydro–Conventional	4,020,629	24	Energy Used by the Company (Excluding Station Use):	
6	Hydro–Pumped Storage		25	Electric Department Only	
7	Other	115	26	Energy Losses:	
8	Less Energy for Pumping		27	Transmission and Conversion Losses	230,957
9	Net Generation *(Enter Total of lines 3 thru 8)*	5,104,373	28	Distribution Losses	441,072
10	Purchases	4,235,750	29	Unaccounted for Losses	
11	Interchanges:		30	TOTAL Energy Losses	672,029
12	In (gross)	3,016,049	31	Energy Losses as Percent of Total on Line 19 6.96 %	
13	Out (gross)	2,036,165	32	TOTAL *(Enter Total of lines 21, 22, 23, 25, and 30)*	9,649,399
14	Net Interchanges *(Lines 12 and 13)*	979,884			
15	Transmission for/by Others (Wheeling)				
16	Received 444,566 MWh				
17	Delivered 1,115,174 MWh				
18	Net Transmission *(Lines 16 and 17)*	(670,608)			
19	TOTAL *(Enter Total of lines 9, 10, 14, and 18)*	9,649,399			

MONTHLY PEAKS AND OUTPUT

1. Report below the information called for pertaining to simultaneous peaks established monthly (in megawatts) and monthly output (in megawatt-hours) for the combined sources of electric energy of respondent.

2. Report in column (b) the respondent's maximum MW load as measured by the sum of its coincidental net generation and purchases plus or minus net interchange, minus temporary deliveries (not interchange) of emergency power to another system. Show monthly peak *including* such emergency deliveries in a footnote and briefly explain the nature of the emergency. There may be cases of commingling of purchases and exchanges and "wheeling," also of direct deliveries by the supplier to customers of the reporting utility wherein segregation of MW demand for determination of peaks as specified by this report may be unavailable. In these cases, report peaks which include these intermingled transactions. Furnish an explanatory note which indicates, among other things, the relative significance of the deviation from basis otherwise applicable. If the individual MW amounts of such totals are needed for billing under separate rate schedules and are estimated, give the amount and basis of estimate.

3. State type of monthly peak reading (instantaneous 15, 30, or 60 minutes integrated).

4. Monthly output is the sum of respondent's net generation for load and purchases plus or minus net interchange and plus or minus net transmission or wheeling. Total for the year must agree with line 19 above.

5. If the respondent has two or more power systems not physically connected, furnish the information called for below for each system.

Name of System: The Washington Water Power Company Gross Requirements

Line No.	Month (a)	Monthly Peak: Megawatts (b)	Day of Week (c)	Day of Month (d)	Hour (e)	Type of Reading (f)	Monthly Output (MWh) *(See Instr. 4)* (g)
33	January	2,305	Monday	17	9 AM	60 Min.	1,140,903
34	February	1,901	Wednesday	02	8 AM	" "	840,815
35	March	1,797	Monday	07	9 AM	" "	875,537
36	April	1,449	Wednesday	27	9 AM	" "	658,212
37	May	1,833	Tuesday	24	4 PM	" "	705,904
38	June	1,428	Thursday	16	11 PM	" "	748,813
39	July	1,346	Thursday	14	11 PM	" "	798,314
40	August	1,115	Thursday	25	3 PM	" "	635,317
41	September	1,221	Wednesday	28	8 AM	" "	652,802
42	October	1,478	Friday	07	3 PM	" "	797,388
43	November	1,496	Tuesday	15	10 AM	" "	821,115
44	December	1,773	Friday	23	10 AM	" "	974,279
45	TOTAL						9,649,399

THE WASHINGTON WATER POWER COMPANY
NET SYSTEM RESOURCES AND REQUIREMENTS
Page 401-A
Year Ended December 31, 1983

Item	Megawatt-Hours Total System	Washington	Idaho	Montana
NET SYSTEM RESOURCES				
Generation (excluding station use):				
Steam	1,083,629	1,013,169		70,460 (1)
Hydro-conventional	4,020,629	968,711	1,268,547	1,783,371
Gas turbine	115	115		
Total Generation	5,104,373	1,981,995	1,268,547	1,853,831
Receipts:				
Purchases (excluding interchange) (See Page 326)	4,235,750	4,012,132	86,433	137,185
Net interchange (See Page 328A)	309,276	(224,701)	1,304,015	(770,038)
Total Purchased Power	4,545,026	3,787,431	1,390,448	(632,853)
State line crossing received	2,305,138	1,047,288	921,645	336,205
Total Receipts	6,850,164	4,834,719	2,312,093	(296,648)
Net Deliveries Outside System:				
Sales outside system (See Note 2, Page 310)	2,767,090	2,190,799	103,593	472,698
Company use surplus				
Total Net Deliveries Outside System	2,767,090	2,190,799	103,593	472,698
State line crossing delivered	2,305,138	187,408	1,065,021	1,052,709
Total Deliveries	5,072,228	2,378,207	1,168,614	1,525,407
Net System Resources	6,882,309	4,438,507	2,412,026	31,776
NET SYSTEM REQUIREMENTS				
Sales to ultimate consumers	5,970,446	3,832,839	2,137,115	492
Sales to other electric utilities (See Page 310)	3,006,924	2,382,614	153,622	470,688
Subtotal - Sales of Electric Energy (See Page 301)	8,977,370	6,215,453	2,290,737	471,180
Sales outside system (See Note 2, Page 310)	2,767,090	2,190,799	103,593	472,698
Total Accounted For	6,210,280	4,024,654	2,187,144	(1,518)
Energy Losses:				
Transmission and conversion	230,957	83,852	115,950	31,155
Distribution	441,072	330,001	108,932	2,139
Total Energy Losses	672,029	413,853	224,882	33,294
Net System Requirements	6,882,309	4,438,507	2,412,026	31,776
Percent Losses of Total System Resources	9.76	9.32	9.32	104.78
OTHER POWER STATISTICS				
Net System Peak Loads and Available Resources (Megawatts):				
Net system peak demand	1,607			
Annual load factor (percent)	48.89			
Plant capability	1,285			
Long-term purchase contracts	415			
Total System Capability	1,700			
Other purchase (sales) arrangements	-0-			
Total Net Resources	1,700			
Plant Statistics - End of Year (Megawatts):				
Nameplate rating	1,188 (1)			
Maximum Capability	1,391 (1)			

Note: (1) Includes Colstrip Generating Plant Unit No. 3. Plant went in service January 10, 1984.

( ) Red Figure

401-A

THE WASHINGTON WATER POWER COMPANY
MONTHLY SYSTEM PEAKS AND RESOURCES
Page 401-B
Year Ended December 31, 1983

Month	Monthly Peak - Entire System: Megawatts	Day of Week	Day of Month	Hour	Type of Reading	Monthly Resources (Mwh): Total System	Washington	Idaho	Montana
January	1,280	Monday	03	6 PM	60 Min.	677,889	417,132	257,636	3,121
February	1,119	Friday	04	8 AM	60 Min.	578,123	399,901	175,450	2,772
March	1,122	Wednesday	16	8 AM	60 Min.	608,770	474,578	131,075	3,117
April	1,079	Tuesday	12	8 AM	60 Min.	527,302	355,319	169,904	2,079
May	1,002	Monday	09	9 AM	60 Min.	513,621	315,605	196,504	1,512
June	896	Wednesday	08	3 PM	60 Min.	471,051	301,663	167,356	2,032
July	907	Friday	22	4 PM	60 Min.	483,362	337,643	143,154	2,565
August	1,026	Monday	08	11 AM	60 Min.	519,658	380,000	136,919	2,739
September	1,088	Thursday	29	8 AM	60 Min.	488,312	295,471	190,446	2,395
October	1,109	Monday	24	9 AM	60 Min.	560,273	304,614	252,608	3,051
November	1,279	Wednesday	30	8 AM	60 Min.	619,530	345,959	270,690	2,881
December	1,607	Friday	23	10 AM	60 Min.	834,418	510,622	320,284	3,512
Total						6,882,309	4,438,507	2,412,026	31,776

401-B

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
The Washington Water Power Company	(1) [X] An Original (2) [ ] A Resubmission	April 30, 1984	Dec. 31, 1983

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Report data for Plant in Service only.
2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report on this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants.
3. Indicate by a footnote any plant leased or operated as a joint facility.
4. If net peak demand for 60 minutes is not available, give data which is available, specifying period.
5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant.
6. If gas is used and purchased on a therm basis, report the Btu content of the gas and the quantity of fuel burned converted to Mcf.
7. Quantities of fuel burned (line 38) and average cost per unit of fuel burned (line 41) must be consistent with charges to expense accounts 501 and 547 (line 42) as shown on line 21.
8. If more than one fuel is burned in a plant, furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name Centralia (b)			Plant Name Othello (c)		
1	Kind of Plant (Steam, Internal Combustion, Gas Turbine or Nuclear)	Steam			Gas Turbine		
2	Type of Plant Construction (Conventional, Outdoor Boiler, Full Outdoor, Etc.)	(1)			Not Applicable		
3	Year Originally Constructed	(1)			6-1-73		
4	Year Last Unit was Installed	(1)			6-1-73		
5	Total Installed Capacity (Maximum Generator Name Plate Ratings in MW)	199.5 (1)			28.2		
6	Net Peak Demand on Plant—MW (60 minutes)	(1)			33		
7	Plant Hours Connected to Load	(1)			4		
8	Net Continuous Plant Capability (Megawatts)						
9	When Not Limited by Condenser Water	(1)			Not Applicable		
10	When Limited by Condenser Water	(1)			Not Applicable		
11	Average Number of Employees	(1)			0		
12	Net Generation, Exclusive of Plant Use — KWh	965,669,000			40,000		
13	Cost of Plant:						
14	Land and Land Rights	277,668			11,198		
15	Structures and Improvements	5,570,003			312,931		
16	Equipment Costs	41,130,621			1,959,013		
17	Total Cost	46,978,292			2,283,142		
18	Cost per KW of Installed Capacity (Line 5)	235.48			80.96		
19	Production Expenses:						
20	Operation Supervision and Engineering	130,881			975		
21	Fuel	15,650,592			2,426		
22	Coolants and Water (Nuclear Plants Only)						
23	Steam Expenses	260,221					
24	Steam From Other Sources						
25	Steam Transferred (Cr.)						
26	Electric Expenses	171,521			3,355		
27	Misc. Steam (or Nuclear) Power Expenses	439,431			63		
28	Rents	4,646					
29	Maintenance Supervision and Engineering	305,856			68		
30	Maintenance of Structures	187,743			233		
31	Maintenance of Boiler (or Reactor) Plant	1,417,188					
32	Maintenance of Electric Plant	204,237			4,866		
33	Maint. of Misc. Steam (or Nuclear) Plant	173,947			2,677		
34	Total Production Expenses	18,946,263			14,663		
35	Expenses per Net KWh	.019620			.366575		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Oil	Coal		Oil		
37	Unit: (Coal—tons of 2,000 lb.)(Oil—barrels of 42 gals.)(Gas—Mcf)(Nuclear—indicate)	Bbl.	Tons		Bbl.		
38	Quantity (Units) of Fuel Burned	2,692	646,280		116		
39	Avg. Heat Cont. of Fuel Burned (Btu per lb. of coal per gal. of oil, or per Mcf of gas)(Give unit if nuclear)	138,000	7,708		138,000		
40	Average Cost of Fuel per Unit, as Delivered f.o.b. Plant During Year	45.69	25.13		None		
41	Average Cost of Fuel per Unit Burned	55.55	23.99		20.91		
42	Avg. Cost of Fuel Burned per Million Btu	9.58	1.56		3.61		
43	Avg. Cost of Fuel Burned per KWh Net Gen.	N/A	.0161		.0606		
44	Average Btu per KWh Net Generation	N/A	10,317		16,808		

FERC FORM NO. 1 (REVISED 12-82)

Note: (1) See Note Page 450.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
The Washington Water Power Company	(1) [X] An Original (2) [ ] A Resubmission	April 30, 1984	Dec. 31, 19 83

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

9. Items under Cost of Plant are based on U.S. of A. accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses classified as Other Power Supply Expenses.

10. For IC and GT plants, report Operating Expenses, Account Nos. 548 and 549 on line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on line 32 "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants.

11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant.

12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type, fuel used, fuel enrichment by type and quantity for the report period, and other physical and operating characteristics of plant.

Plant Name Spokane N.I. (d)	Plant Name Kettle Falls (e)	Plant Name (f)	Line No.
Gas Turbine	Steam		1
Not Applicable	Conventional		2
12-2-78	1983		3
12-2-78	1983		4
61.2	50.7		5
68	44.5		6
4	656		7
			8
Not Applicable	42.5		9
Not Applicable	Not Applicable		10
0	29		11
~~75,000~~ 244,000	47,500,000 (3) 24,935,000		12
			13
129,664	251,926		14
248,488	20,007,904		15
10,715,317	66,277,298		16
11,093,469	86,537,128		17
181.27	1706.85		18
			19
122	13,348		20
233,348	547,746		21
			22
	13,283		23
			24
			25
27,169	25,485		26
1,529	22,144		27
			28
746	3,392		29
90	1,276		30
	31,262		31
11,067	18,261		32
1,937	7,674		33
276,008	683,871		34
3.680107	.014397		35

(d)			(e)			(f)			Line No.
Oil	Gas		Gas (4)	Wood					36
	MCF			Ton					37
None	1,694			37,821					38
	10.47×10^5			4,300/lb.					39
	4.93 (2)			12.50					40
	4.93 (2)			14.48					41
	4.71 (2)			1.68					42
	.1111 (2)			.0220					43
	23,648			13,044					44

Notes: (2, 3 & 4) See Notes Page 450.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
The Washington Water Power Company	(1) [X] An Original (2) [ ] A Resubmission	April 30, 1984	Dec. 31, 19 83

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)
Average Annual Heat Rates and Corresponding Net MWh Output for Most Efficient Generating Units

1. Report only the most efficient generating units (not to exceed 10 in number) which were operated at annual capacity factors of 50 percent or higher. List only unit type installations, i.e., single boiler serving one turbine-generator. It is not necessary to report single unit plants on this page. Do not include non-condensing or automatic extraction-type turbine units operated for processing steam and electric power generation.
2. Annual Unit Capacity Factor =

$$\frac{\text{Net Generation—Kwh:}}{\text{Unit KW. Capacity (as included in plant total--line 5, p. 402)} \times 8{,}760 \text{ hours}}$$

3. Report annual system heat rate for total conventional steam-power generation and corresponding net generation (line 11).
4. Compute all heat rates on this page and also on pages 403 and 404 on the basis of total fuel burned, including burner lighting and banking fuel.

Line No.	Plant Name (a)	Unit No. (b)	MW (Generator Rating at Maximum Hydrogen Pressure) (c)	Btu Per Net MWh (d)	Net Generation Thousand MWh (e)	Kind of Fuel (f)
1						
2	Centralia Steam Plant (1)	(1)	(1)	(1)	(1)	(1)
3						
4						
5						
6						
7						
8						
9						
10						
	Total System Steam Plants					
11						

Note: (1) Jointly owned. For complete details, see FERC Form 1 of Pacific Power & Light Company.

Attachment 5-4
Forecasts and Backcasts of Average System Costs and Loads for FY 2002 Through 2008
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
The Washington Water Power Company	(1) ☒ An Original (2) ☐ A Resubmission	April 30, 1984	Dec. 31, 19 83

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Large plants are hydro plants of 10,000 Kw or more of installed capacity (name plate ratings).
2. If any plant is leased, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. If licensed project, give project number.
3. If net peak demand for 60 minutes is not available, give that which is available, specifying period.
4. If a group of employees attends more than one generating plant, report on line 11 the approximate average number of employees assignable to each plant.

Line No.	Item (a)	Little Falls (b)	2545 Long Lake (c)	2545 Upper Falls (d)	2545 Nine Mile (e)
1	Kind of Plant (Run-of-River or Storage)	Run-of-River	Storage	Run-of-River	Run-of-River
2	Type of Plant Construction (Conventional or Outdoor)	Conv.	Conv.	Conv.	Conv.
3	Year Originally Constructed	1910	1915	1922	1908
4	Year Last Unit was Installed	1911	1924	1922	1910
5	Total Installed Capacity (Generator Name Plate Ratings in MW)	32	70	10	12
6	Net Peak Demand on Plant—Megawatts (60 minutes)	36	73	12	20
7	Plant Hours Connected to Load	8,760	8,760	8,518	8,752
8	Net Plant Capability (In megawatts)				
9	(a) Under the Most Favorable Oper. Conditions	36	72.5	10.2	18
10	(b) Under the Most Adverse Oper. Conditions	26.8	57.1	7.0	13.9
11	Average Number of Employees	2	6	0	6
12	Net Generation, Exclusive of Plant Use – KWh	216,842,000	493,064,000	78,873,000	130,887,000
13	Cost of Plant:				
14	Land and Land Rights	125,371	1,231,568	63,564	26,993
15	Structures and Improvements	587,898	1,080,797	367,239	315,252
16	Reservoirs, Dams, and Waterways	752,163	3,555,539	717,127	1,027,104
17	Equipment Costs	3,086,693	4,140,383	528,563	857,197
18	Roads, Railroads, and Bridges				
19	TOTAL Cost *(Enter Total of lines 14 thru 18)*	4,552,125	10,008,287	1,676,493	2,226,546
20	Cost per KW of Installed Capacity (Line 5)	142.25	142.98	167.65	185.55
21	Production Expenses:				
22	Operation Supervision and Engineering	15,133	16,351	6,183	30,025
23	Water for Power	802	1,411	369	565
24	Hydraulic Expenses			6,827	715
25	Electric Expenses	79,819	132,201	96,848	156,161
26	Misc. Hydraulic Power Generation Expenses	9,353	24,330	9,674	15,045
27	Rents				
28	Maintenance Supervision and Engineering	2,150	8,894	561	762
29	Maintenance of Structures	6,233	8,356	36	2,972
30	Maintenance of Reservoirs, Dams, and Waterways	99,112	142,648	3,583	10,571
31	Maintenance of Electric Plant	45,967	59,583	27,097	20,888
32	Maintenance of Misc. Hydraulic Plant	318	3,579	142	
33	Total Production Expenses *(Total lines 22 thru 32)*	258,887	397,353	151,320	237,704
34	Expenses per Net KWh	.001194	.000806	.001919	.001816

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HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."

6. Report as a separate plant any plant equipped with combinations of steam, hydro, internal combustion engine, or gas turbine equipment.

2545 Post Falls (f)	2058 Cabinet Gorge (g)	2075 Noxon Rapids (h)		FERC Licensed Project No. Plant Name (i)	Line No.
Storage	Storage	Storage			1
Conv.	Outdoor	Outdoor			2
1906	1952	1959			3
1980	1953	1977			4
14.8	200	397			5
19	234	501			6
8,760	8,760	8,760			7
					8
18	230	554			9
13.2	190	370			10
2	14	13			11
106,286,000	1,162,261,000	1,783,371,000			12
					13
1,079,879	7,542,223	31,107,614			14
323,802	7,655,809	9,125,414			15
1,182,770	16,206,398	28,836,922			16
2,379,142	12,676,377	34,491,142			17
	820,604	88,694			18
4,965,593	44,901,411	103,649,786			19
335.51	224.51	261.08			20
					21
41,721	39,942	47,260			22
2,269					23
5,573	2,964	1,068			24
33,230	321,684	325,469			25
18,597	43,434	45,280			26
	6,002	15,552			27
1,990	6,661	4,593			28
6,214	19,921	29,541			29
5,028	3,940	2,570			30
35,776	156,126	152,716			31
109	5,073	21,784			32
150,507	605,747	645,833			33
.001416	.000521	.000362			34

Attachment 5-4
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FERC FORM NO. 1 (REVISED 12-81)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
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GENERATING PLANT STATISTICS (Small Plants)

1. Small generating plants are steam plants of less than 25,000 Kw; internal combustion and gas turbine-plants, conventional hydro plants and pumped storage plants of less than 10,000 Kw installed capacity (name plate rating).
2. Designate any plant leased from others, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, and give a concise statement of the facts in a footnote. If licensed project, give project number in footnote.
3. List plants appropriately under subheadings for steam, hydro, nuclear, internal combustion and gas turbine plants. For nuclear, see instruction 11, page 403.
4. If net peak demand for 60 minutes is not available, give that which is available, specifying period.
5. If any plant is equipped with combinations of steam, hydro internal combustion or gas turbine equipment, report each as a separate plant. However, if the exhaust heat from the gas turbine is utilized in a steam turbine regenerative feed water cycle, or for preheated combustion air in a boiler, report as one plant.

Line No.	Name of Plant (a)	Year Orig. Const. (b)	Installed Capacity-Name Plate Rating (In MW) (c)	Net Peak Demand MW (60 Min.) (d)	(2) Net Generation Excluding Plant Use (e)	Cost of Plant (f)	Plant Cost per MW Inst. Capacity (g)	Production Expenses: Operation Exc'l. Fuel (h)	Production Expenses: Fuel (i)	Production Expenses: Maintenance (j)	Kind of Fuel (k)	Fuel Cost (In cents per million Btu) (l)
1	Hydro											
2	Meyers Falls (1)	1915	1.2	1.35	4,777,000	403,385	336,154	115,525		76,469		
3	Monroe Street (3)	1903	7.2	7.00	44,268,000	3,704,119	514,461	91,578		62,694		
4												
5												
6												
7												
8												
9												
10												
11												
12												
13												
14												
15	(1) Land and related water rights leased from Dr. Lee W. Cagle for $7,200.00 per annum. Respondent owns dam, structures, machinery and											
16	related equipment and pays all taxes relating to all real property. Respondent operates plant and receives all power output. Also											
17	pays all operating expenses of plant. Lessor is not an associated company. Licensed Project No. 2544.											
18												
19	(2) In Kwh.											
20												
21	(3) Licensed Project No. 2545.											
22												
23												
24												
25												
26												
27												
28												

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
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CHANGES MADE OR SCHEDULED TO BE MADE IN GENERATING PLANT CAPACITIES

Give below the information called for concerning changes in electric generating plant capacities during the year.

A. Generating Plants or Units Dismantled, Removed from Service, Sold, or Leased to Others During Year

1. State in column (b) whether dismantled, removed from service, sold, or leased to another. Plants removed from service include those not maintained for regular or emergency service.
2. In column (f), give date dismantled, removed from service, sold, or leased to another. Designate complete plants as such.

Line No.	Name of Plant (a)	Disposition (b)	Installed Capacity (In megawatts) Hydro (c)	Steam (d)	(Other) (e)	Date (f)	If Sold or Leased to Another, Give Name and Address of Purchaser or Lessee (g)
1	None						
2							
3							
4							
5							
6							
7							

B. Generating Units Scheduled for or Undergoing Major Modifications

Line No.	Name of Plant (a)	Character of Modification (b)	Installed Plant Capacity After Modification (In megawatts) (c)	Estimated Dates of Construction Start (d)	Completion (e)
8	None				
9					
10					
11					
12					
13					
14					

C. New Generating Plants Scheduled for or Under Construction

Line No.	Plant Name and Location (a)	Type (Hydro, Pumped Storage, Steam, Internal Combustion, Gas-Turbine, Nuclear, etc.) (b)	Installed Capacity (In megawatts) Initial (c)	Ultimate (d)	Estimated Dates of Construction Start (e)	Completion (f)
15	Reference is made to Page 411-A.					
16						
17						
18						
19						
20						
21						

D. New Units in Existing Plants Scheduled for or Under Construction

Line No.	Plant Name and Location (a)	Type (Hydro, Pumped Storage, Steam, Internal Combustion, Gas-Turbine, Nuclear, etc.) (b)	Unit No. (c)	Size of Unit (In megawatts) (d)	Estimated Dates of Construction Start (e)	Completion (f)
22	None					
23						
24						
25						
26						
27						
28						

Plant Name and Location (a)	Type (Hydro, Pumped Storage, Steam, Internal Combustion, Gas-Turbine, Nuclear, etc.) (b)	Installed Capacity (In megawatts) Initial (c)	Ultimate (d)	Estimated Dates of Construction Start (e)	Completion (f)
5% of WPPSS Nuclear Project No. 3, Grays Harbor Co., WA (1)	Nuclear	1,240	1,240	1973	1986
15% of Colstrip Units No. 3 & 4, Colstrip, MT (3)	Coal	700	1,400	1973	1985
Creston, WA project	Coal	(2)	(2)	(2)	(2)

Notes: (1) WPPSS Nuclear Project No. 3 is currently in a construction delay. See Note 9, Notes to the Financial Statements, page 122L through 122R, for further discussion.

(2) *The Company has a site certificate for the Creston Project. Construction timing, annual* construction expenditure levels and ultimate size of the plant are subject to final determination of ownership participation, licensing and resource requirements.

(3) Colstrip Unit No. 3 went in service January 10, 1984.

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STEAM-ELECTRIC GENERATING PLANTS

1. Include on this page steam-electric plants of 25,000 Kw (name plate rating) or more of installed capacity.
2. Report the information called for concerning generating plants and equipment at end of year. Show unit type installation, boiler, and turbine-generator, on same line.
3. Exclude plant, the book cost of which is included in Account 121, *Nonutility Property*.
4. Designate any generating plant or portion thereof for which the respondent is not the sole owner. If such property is leased from another company give name of lessor, date and term of lease, and annual rent. For any generating plant, other than a leased plant or portion thereof for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) as to such matters as percent ownership by respondent, name of co-owner, basis of sharing

Line No.	Name of Plant (a)	Location of Plant (b)	Boilers (Include both ratings for the boiler and the turbine-generator of dual-rated installations) Number and Year Installed (c)	Kind of Fuel and Method of Firing (d)	Rated Pressure (In psig) (e)	Rated Steam Temperature (Indicate reheat boilers as 1050/1000) (f)	Rated Max. Continuous M lbs. Steam per Hour (g)
1	Centralia Plant	Centralia, WA	(1)	(1)	(1)	(1)	(1)
2	Kettle Falls	Kettle Falls, WA	1 1983	Wood Waste	1500	950	415
3							
4							
5							
6							
7							
8							
9							
10							
11							
12							
13							
14							
15							
16							
17							
18							
19							
20	Note: (1) Centralia Plant is jointly owned. Plant capacity in column (s) represents only						
21	Respondent's 15% share. Details will be reported by Pacific Power & Light Company.						
22	Respondent's share of plant and expense is included in its financial statements.						
23							
24							
25							
26							
27							
28							
29							
30							
31							
32							
33							

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
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STEAM-ELECTRIC GENERATING PLANTS (Continued)

output, expenses or revenues, and how expenses and/or revenues are accounted for and accounts affected. Specify if lessor, co-owner, or other party is an associated company.

5. Designate any generating plant or portion thereof leased to another company and give name of lessee, date and term of lease and annual rent, and how determined. Specify whether lessee is an associated company.

6. Designate any plant or equipment owned, not operated, and not leased to another company. If such plant or equipment was not operated within the past year explain whether it has been retired in the books of account or what disposition of the plant or equipment and its book cost are contemplated.

7. Report gas-turbines operated in a combined cycle with a conventional steam unit with its associated steam unit.

Turbine-Generators
(Report cross-compound turbine-generator units on two lines — H.P. section and I.P. section. Designate units with shaft connected boiler feed pumps. Give capacity rating of pumps in terms of full load requirements)

Year Installed (h)	Turbines (Include both ratings for the boiler and the turbine-generator of dual-rated installations): Max. Rating Mega-watt (i)	Type (Indicate tandem-compound (TC); cross-compound (CC); single casing (SC); topping unit (T); and noncondensing (NC). Show back pressures) (j)	Steam Pressure at Throttle psig. (k)	RPM (l)	Generators: Name Plate Rating in Megawatts: At Minimum Hydrogen Pressure (m)	At Maximum Hydrogen Pressure (Include both ratings for the boiler and the turbine-generator of dual-rated installations) (n)	Hydrogen Pressure (Designate air cooled generators): Min. (o)	Max. (p)	Power Factor (q)	Voltage (In KV) (If other than 3 phase, 60 cycle, indicate other characteristic) (r)	Plant Capacity, Maximum Generator Name Plate Rating (Should agree with column (n)) (s)	Line No.
(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	199,469	1
1983	46	SC	1450	3600	35.9	50.7	0.5	30	.95	13.8	50,700	2
												3
												4
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
The Washington Water Power Company	(1) [X] An Original (2) [ ] A Resubmission	April 30, 1984	Dec. 31, 19 83

HYDROELECTRIC GENERATING PLANTS

1. Report on this page Hydro plants of 10,000 Kw (name plate rating) or more of installed capacity.
2. Report the information called for concerning generating plants and equipment at end of year. Show associated prime movers and generators on the same line.
3. Exclude from this schedule, plant, the book cost of which is included in Account 121, *Nonutility Property*.
4. Designate any plant or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and term of lease, and annual rent. For any generating plant, other than a leased plant, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving

Line No.	Name of Plant (a)	Location (b)	Name of Stream (c)	Water Wheels (In column (e), indicate whether horizontal or vertical. Also indicate type of runner – Francis (F), fixed propeller (FP), automatically adjustable propeller (AP), Impulse (I). Designate reversible type units by appropriate footnote) Attended or Unattended (d)	Type of Unit (e)	Year Installed (f)	Gross Static Head With Pond Full (g)
1	STATE OF WASHINGTON						
2	Upper Falls	Spokane, WA	Spokane River	U	Vert. F	1922	64.5
3	Nine Mile	5 mi. northwest of	Spokane River	A	Hor. F		70
4		Spokane, WA			#2-3	1908	
5					#1-4	1910	
6	Long Lake	25 mi. northwest of	Spokane River	A	Hor. F		174
7		Spokane, WA			#1-2	1915	
8					#3	1919	
9					#4	1924	
10	Little Falls	28 mi. northwest of	Spokane River	A	Hor. F		84
11		Spokane, WA			#1-2-3	1910	
12					#4	1911	
13							
14	STATE OF IDAHO						
15	Post Falls	Post Falls, Idaho	Spokane River	A	Hor. F		62 (1)
16					#2-3-4	1906	
17					#1	1907	
18					#5	1908	
19					#6	1980	
20	Cabinet Gorge	Near Cabinet, ID	Clark Fork River	A	Vert. FP		111
21					#3-4	1952	
22					#1-2	1953	
23							
24	STATE OF MONTANA						
25	Noxon Rapids	3 mi. upstream from	Clark Fork River	A	Vert. F		156
26		Noxon, MT			#1-2-3	1959	
27					#4	1960	
28					#5	1977	
29							
30							
31							
32							
33	Note: (1) Based on Coeur d'Alene Lake elevation of 2,128.00 feet.						
34							
35							
36							
37							
38							
39							
40							

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HYDROELECTRIC GENERATING PLANTS (Continued)

particulars (details) as to such matters as percent ownership by respondent, name of co-owner, basis of sharing output, expenses, or revenues, and how expenses and/or revenues are accounted for and accounts affected. Specify if lessor, co-owner, or other party is an associated company.

5. Designate any plant or portion thereof leased to another company, and give name of lessee, date and term of lease and annual rent, and how determined. Specify whether lessee is an associated company.

6. Designate any plant or equipment owned, not operated, and not leased to another company. If such plant or equipment was not operated within the past year explain whether it has been retired in the books of account or what disposition of the plant or equipment and its book cost are contemplated.

Water Wheels (Continued)			Generators							Total Installed Generating Capacity (Name Plate Ratings) (In megawatts)	Line No.
Design Head (h)	RPM (i)	Maximum Hp. Capacity of Unit at Design Head (j)	Year Installed (k)	Voltage (l)	Phase (m)	Frequency or d.c. (n)	Name Plate Rating of Unit (In megawatts) (o)	Number of Units in Plant (p)	(q)		
											1
64	105.8	14,250	1922	4,000	3	60	10	1	10	2
50	240	5,000		2,200	3	60	3	4	12	3
			1908							4
			1910							5
163	200	22,500		4,000	3	60	17.5	4	70	6
			1915							7
			1919							8
			1924							9
66	150	9,000		4,000	3	60	8	4	32	10
			1910							11
			1911							12
										13
										14
50	138	3,260		2,300	3	60	2.25	5	11.25	15
			1906							16
			1907							17
			1908							18
48	164	5,500	1980				3.5	1	3.5	19
99	120	70,500		13,800	3	60	50	4	200	20
			1952							21
			1953							22
										23
										24
152	105.9	172,000		14,400	3	60	70.72	4	282.88	25
			1959							26
			1960							27
			1977				114	1	114	28
										29
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
The Washington Water Power Company	(1) [X] An Original (2) [ ] A Resubmission	April 30, 1984	Dec. 31, 19 83

INTERNAL-COMBUSTION ENGINE AND GAS-TURBINE GENERATING PLANTS

1. Include on this page internal-combustion engine and gas-turbine plants of 10,000 kilowatts and more.
2. Report the information called for concerning plants and equipment at end of year. Show associated prime movers and generators on the same line.
3. Exclude from this page, plant, the book cost of which is included in Account 121, *Nonutility Property*.
4. Designate any plants or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and term of lease, and annual rent. For any generating plant other than a leased plant, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) as to such matters as percent of ownership by respondent, name of co-owner, basis of sharing output, expenses, or revenues, and how expenses and/or revenues are accounted for and accounts affected. Specify if lessor, co-owner, or other party is an associated company.

Line No.	Name of Plant (a)	Location of Plant (b)	Prime Movers *(In column (e), indicate basic cycle for gas-turbine as open or closed; indicate basic cycle for internal-combustion as 2 or 4)* Interal-Combustion or Gas-Turbine (c)	Year Installed (d)	Cycle (e)	Belted or Direct Connected (f)
1	Othello	Othello, WA	Gas Turbine	1973	Open	Pneumatic
2	Spokane Northeast	Spokane, WA	Gas Turbine	1978	Open	Pneumatic
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4						
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INTERNAL-COMBUSTION ENGINE AND GAS-TURBINE GENERATING PLANTS (Continued)

5. Designate any plant or portion thereof leased to another company and give name of lessee, date and term of lease and annual rent, and how determined. Specify whether lessee is an associated company.

6. Designate any plant or equipment owned, not operated, and not leased to another company. If such plant or equipment was not operated within the past year, explain whether it has been retired in the books of account or what disposition of the plant or equipment and its book cost are contemplated.

Prime Movers (Continued)	Generators						Total Installed Generating Capacity (Name plate ratings) (In megawatts)	Line No.
Rated Hp of Unit (g)	Year Installed (h)	Voltage (i)	Phase (j)	Frequency or d.c. (k)	Name Plate Rating of Unit (In megawatts) (l)	Number of Units in Plant (m)	(n)	
90,000	1973	13.8 Kv	3∅	60 HZ	28.2	One	28.2	1
180,000	1978	13.8 Kv	3∅	60 HZ	61.2	One	61.2	2
								3
								4
								5
								6
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								24
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								27
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								36
								37
								38
								39
								40

Attachment 5-4
Forecasts and Backcasts of Average System Costs and Loads for FY 2002 Through 2008
WP-07-E-BPA-83
Page 286

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
The Washington Water Power Company	(1) [X] An Original (2) [ ] A Resubmission	April 30, 1984	Dec. 31, 1983

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.

2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.

3. Report data by individual lines for all voltages if so required by a State commission.

4. Exclude from this page any transmission lines for which plant costs are included in Account 121, *Nonutility Property*.

5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole, wood, or steel; (2) H-frame, wood, or steel poles; (3) tower; or (4) underground construction. If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.

6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION		VOLTAGE (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole Miles) (In the case of underground lines, report circuit miles)		Number of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structures of Line Designated (f)	On Structures of Another Line (g)	(h)
1	Beacon Sub #4	BPA Bell Sub)	230	230	Steel Tower	0.53		1
2		)	230	230	H Type	5.48		1
3	Beacon Sub #5	BPA Bell Sub	230	230	H Type	6.04		1
4	Beacon Sub	Cab. Gorge Plt.)	230	230	Steel Tower		0.52	1
5		)	230	230	H Type	77.17		1
6	Beacon Sub	Lolo Sub)	230	230	Steel Tower	0.50		1
7		)	230	230	H Type	107.03		1
8	Noxon Plant	Pine Creek Sub	230	230	H Type	43.14		1
9	Cab. Gorge Plt.	Noxon Plt.	230	230	H Type	18.51		1
10	Benewah Sw. Sta.	Pine Creek Sub)	230	230	Steel Tower	0.48		1
11		)	230	230	H Type	42.28		1
12	Divide Creek	Lolo Sub)	230	230	Steel Tower	0.11		1
13		)	230	230	H Type	43.07		1
14	Lolo Sub	Walla Walla)	230	230	Steel Tower	0.08		1
15		)	230	230	H Type	46.23		1
16	Walla Walla	Wanapum)	230	230	Alum.	0.20		1
17		)	230	230	H Type	77.58		1
18	(Libby) BPA Line	Noxon Plant	230	230	Steel Tower	0.79		1
19	BPA Hot Spgs. #1	Noxon Plant	230	230	Steel Tower	0.79		1
20	BPA Hot Spgs. #2	Noxon Plant)	230	230	Steel Tower		1.60	1
21		)	230	230	H Type	68.45		1
22	BPA Line	West Side Sub	230	230	Steel Pole	3.98		2
23	Colstrip	Broadview	230	230	Steel Tower	112.75*		1
24								
25	Total		230	230		655.19	2.12	
26								
27	Total		115	115		1,441.31		
28								
29	Total		60	60		36.12		
30								
31	Total Underground		115	115		0.69		
32								
33								
34								
35	*Respondent's 6.6% share							
36					TOTAL	2,133.31	2.12	

FERC FORM NO. 1 (REVISED 12-81)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
The Washington Water Power Company	(1) [X] An Original (2) [ ] A Resubmission	April 30, 1984	Dec. 31, 19 83

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report lower voltage lines and higher voltage lines as one line. Designate in a footnote if you do not include lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g).

8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.

9. Designate any transmission line leased to another company and give name of lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.

10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in column (j) land, land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
795McMACSR								1
795McMACSR	17,523	193,370	210,893	141			141	2
1272McMAL	29,723	305,508	335,231	70	4,815		4,885	3
795McMACSR								4
795McMACSR	118,082	2,841,914	2,959,996	733	29,471	657	30,861	5
795McMACSR								6
1272McMAL	475,113	2,939,790	3,414,903	3,307	10,603		13,910	7
954McMAL	22,797	1,752,683	1,775,480	884	6,422	1,714	9,020	8
954McMAL	48,871	696,452	745,323	510	20,924	745	22,179	9
954McMAL								10
954McMAL	206,506	1,295,183	1,501,689	2,465	43,921	10	46,396	11
1272McMAL								12
1272McMAL	86,228	1,875,844	1,962,072			488	488	13
1272McMAL								14
1272McMAL	233,370	2,122,232	2,355,602					15
1272McMAL								16
1272McMAL	70,781	1,762,864	1,833,645	591			591	17
1272McMAL	54,370	101,305	155,675			25	25	18
1272McMAL								19
1272McMAL								20
1272McMAL	139,237	1,644,100	1,783,337	2,416			2,416	21
1272McMACSR	97,564	587,122	684,686					22
795McMACSR		2,331,615	2,331,615					23
								24
	1,600,165	20,449,982	22,050,147	11,117	116,156	3,639	130,912	25
								26
	3,304,278	31,924,090	35,228,368	48,024	209,351	2,225	259,600	27
								28
	29,598	600,464	630,062	257	(120)		137	29
								30
		964,846	964,846					31
								32
								33
								34
								35
	4,934,041	53,939,382	58,873,423	59,398	325,387	5,864	390,649	36

Attachment 5-4
Forecasts and Backcasts of Average System Costs and Loads for FY 2002 Through 2008
WP-07-E-BPA-83
Page 188

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
The Washington Water Power Company	(1) [X] An Original (2) [ ] A Resubmission	April 30, 1984	Dec. 31, 19 83

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, *Nonutility Property*.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole, wood, or steel; (2) H-frame, wood, or steel poles; (3) tower; or (4) underground construction. If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole Miles) (In the case of underground lines, report circuit miles) On Structures of Line Designated (f)	LENGTH On Structures of Another Line (g)	Number of Circuits (h)
1	Centralia	BPA Paul	500 Kv	(1)	(1)	(1)		(1)
2								
3								
4	Centralia	BPA Tap	230 Kv	(1)	(1)	(1)		(1)
5								
6								
7								
8								
9								
10								
11								
12								
13								
14								
15								
16								
17	Note: (1) 15% of Respondent's share of jointly owned facilities.							
18	(For complete details see FERC Form 1 of Pacific Power & Light Company.)							
19								
20								
21								
22								
23								
24								
25								
26								
27								
28								
29								
30								
31								
32								
33								
34								
35								
36					TOTAL			

Name of Respondent	This Report Is:	Date of Report	Year of Report
The Washington Water Power Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr) April 30, 1984	Dec. 31, 1983

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report lower voltage lines and higher voltage lines as one line. Designate in a footnote if you do not include lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g).

8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.

9. Designate any transmission line leased to another company and give name of lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.

10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in column (j) land, land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
(1)		66,379	66,379	(1)	(1)	(1)	(1)	1
								2
								3
(1)	13,465	32,033	45,498	(1)	(1)	(1)	(1)	4
								5
								6
								7
								8
								9
								10
								11
								12
								13
								14
								15
								16
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								18
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								28
								29
								30
								31
								32
								33
								34
								35
	13,465	98,412	111,877					36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
The Washington Water Power Company	(1) [X] An Original (2) [ ] A Resubmission	April 30, 1984	Dec. 31, 1983

TRANSMISSION LINES ADDED DURING YEAR

1. Report below the information called for concerning transmission lines added or altered during the year. It is not necessary to report minor revisions of lines.

2. Provide separate subheadings for overhead and underground construction and show each transmission line separately. If actual costs of completed construction are not readily available for reporting in columns (l) to (o), it is permissible to report in these columns the estimated final completion costs. Designate, however, if estimated amounts are reported. Include costs of Clearing Land and Rights-of-Way, and Roads and Trails, in column (l) with appropriate footnote, and costs of Underground Conduit in column (m).

3. If design voltage differs from operating voltage, indicate such fact by footnote; also where line is other than 60 cycle, 3 phase, indicate such other characteristic.

Line No.	LINE DESIGNATION From (a)	LINE DESIGNATION To (b)	Line Length in Miles (c)	SUPPORTING STRUCTURE Type (d)	SUPPORTING STRUCTURE Average Number per Mile (e)	CIRCUITS PER STRUCTURE Present (f)	CIRCUITS PER STRUCTURE Ultimate (g)	CONDUCTORS Size (h)	CONDUCTORS Specification (i)	CONDUCTORS Configuration and Spacing (j)	Voltage KV (Operating) (k)	LINE COST (Thousands of Dollars) Land and Land Rights (l)	Poles, Towers, and Fixtures (m)	Conductors and Devices (n)	Total (o)
1	Mullan	Lucky Friday Sub	0.14	Pole	8	1	1	556	ACSR	SPT	115		15	38	53
2	Met Chip	Arden	3.56	Pole	16	1	1	556	AAC	SPT	115	1	98	132	231
3	Arden	Orin	4.31	Pole	16	1	1	556	AAC	SPT	115	2	106	144	252
4	Colville	Kettle Falls	12.46	Pole	16	1	1	556	AAC	SPT	115	187	340	553	1,080
5	Col-Rep (BPA)	Kettle Falls	0.24	Pole	10	1	1	556	AAC	HF	115		7	14	21
6	CDA 15th St Tap	CHG. 2	3.16	Pole	10	1	1	795	AAC	SPT	115	15	98	203	316
7	CHG. 2	Dalton	0.08	Pole	10	1	1	556	AAC	SPT	115				
8	Old Tap Point	CDA 15th St	0.92	Pole	10	1	1	556	AAC	SPT	115	32	47	52	131
9	Colfax (old)	N. Lewiston	0.29	Pole	8	1	1	556	ACSR	HF	115	30	62	60	152
10	Walla Walla (old)	N. Lewiston	0.30	Pole	8	1	1	556	ACSR	HF	115				
11	Devils Gap-Lind	Reardan	0.07	Pole	N/A	1	1	4/0	ACSR	HF	115		14	25	39
12	Lolo-N. Lew.	Old N. Lewiston	0.12	Pole	8	1	1	4/0	ACSR	HF	115		12	7	19
13	Moscow	N. Lewiston	0.20	Pole	10	1	1	556	ACSR	HF	115				
14	Hatwai	N. Lewiston	7.00	Pole	7	1	1	1590	ACSR	HF	230	107	559	553	1,219
15	Latah	Benewah	5.19	Pole	10	1	1	556	ACSR	HF & SPT	115	12	79	134	225
16	Stratford	Odessa	29.82	Pole	10	1	1	556	ACSR	HF	115	11	466	699	1,176
17															
18															
19															
20	Notes: Items	1-8 and 10-14	New construction.												
21	Items	9 and 10	New construction and reconductor.												
22	Item	1[illegible] and 17	Reconductor.												
23	Items	6 and 7	Line costs are grouped in Item 6.												
24	Items	9, 10 and 14	Line costs are grouped in Item 9.												
25															
26															
27															
28		TOTAL										397	1,903	2,614	4,914

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
The Washington Water Power Company	(1) [X] An Original (2) [ ] A Resubmission	April 30, 1984	Dec. 31, 19 83

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of less than 10,000 Kva, except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).
5. Show in columns (i), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)	Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers in Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (k)
1	STATE OF WASHINGTON										
2	Addy	Distr. Unattended	115	13.8		12	1		Frcd Oil & Air Fan	1	20
3	Airway Heights	Distr. Unattended	115	13.8		12	1		Frcd Oil & Air Fan	1	20
4	Barker Road	Distr. Unattended	110	13.8		10	3		Portable Fan	1	12.5
5	Beacon	Transm & Dist Attnd	230/115	115/13.8	13.8	395	5	1	Portable Fan	1	400
6	Boundary	Transm Unattended	230	115	13.8	75	1				
7	Chester	Distr. Unattended	115	13.8		24	2		Frcd Oil & Air Fan	2	40
8	Chewelah 110 Kv	Distr. Unattended	115	13.8		15	3				
9	Colbert	Distr. Unattended	115	13.8		12	1		Frcd Oil & Air Fan	1	20
10	College & Walnut	Distr. Unattended	115	13.8		24	2		Frcd Air Fan	2	32
11	Colville 110 Kv	Distr. Unattended	115	13.8		12	1		Frcd Oil & Air Fan	1	20
12	Dry Gulch	Distr. Unattended	115	13.8		12	1		Frcd Oil & Air Fan	1	20
13	East Colfax	Distr. Unattended	115	13.8		12	1		Capacitors & Frcd	864	20
14	Fairchild	Transm & Dist Unatd	115	60		16.5	3	1	Oil & Air Fan		20
15	Fort Wright	Distr. Unattended	115	13.8		24	2		Two Stage Fan	2	40
16	Francis and Cedar	Distr. Unattended	115	13.8		24	2		Frcd Air Fan	2	32
17	Gifford	Distr. Unattended	115	34		12	1				
18	Greenwood	Distr. Unattended	115	13.8		12	1		Portable Fan	1	15
19	Industrial Park	Distr. Unattended	115	13.8		15.8	2		Two Stage & Portable Fan	2	24.7
20	Kettle Falls	Distr. Unattended	115	13.8		12			Frcd Oil & Air Fan	2	20
21	Liberty Lake	Distr. Unattended	115	13.8		24	2		Two Stage Fan	2	40
22	Lind	Distr. Unattended	115	13.8/[illegible]		10	3	1			
23	Little Falls 115/34 Kv	Distr. Unattended	115	34		12	1				
24	Lyons & Standard	Distr. Unattended	115	13.8		30	2		Two Stage Fan	2	60
25	Metro	Distr. Unattended	115	13.8		32	2		Two Stage Fan	2	40

Next Page is 427

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
The Washington Water Power Company	(1) [X] An Original (2) [ ] A Resubmission	April 30, 1984	Dec. 31, 19 83

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of less than 10,000 Kva, except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).
5. Show in columns (i), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)	Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers in Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (k)
1	Millwood	Transm & Dist Unatd	115	60	13.8	44	3	1	Frcd & Air Frcd Oil & AirFan	3	61
2	Ninth & Central	Distr. Unattended	115	13.8		24	2		Frcd & Two Stage Fan	2	36
3	Northeast	Distr. Unattended	115	13.8		24	2		Two Stage Fan	2	40
4	Northwest	Distr. Unattended	60/115	13.8		36.9	6	1	Two Stage Fan	2	52.9
5	Opportunity	Distr. & Whsle Unatd	13.8/115	4/13.8		24	2		Two Stage Fan	2	40
6	Orin	Transm & Dist Unatd	115	60	13.8	22.5	4		Portable Fan	1	24.4
7	Othello	Distr. Unattended	115	13.8		12	1		Frcd Oil & AirFan & Capctrs.	865	41.6
8	Palouse	Transm & Dist Unatd	115	60	13.8	22.5	5		Portable Fan	2	27.3
9	Post Street	Distr. Attended	115/13.8	13.8/4		61	10	1	Frcd Oil & Water Fan	7	64.4
10	Pound Lane	Distr. Unattended	115	13.8		24	2		Frcd Oil & Air Fan	2	40
11	Pullman	Distr & Trfr Unatd	115	4/13.8		24	7	1	Portable Fan	7	30
12	Ross Park	Distr. Unattended	115	13.8		30	2		Two Stage Fan	2	50
13	Roxboro	Distr. Unattended	115	24		24	2		Two Stage Fan	2	40
14	Silver Lake	Distr. Unattended	115	13.8		12	1		Frcd Oil & Air Fan	1	20
15	Southeast	Distr. Unattended	115	13.8		24	2		Frcd Air & Two Stage Fan	2	40
16	South Othello	Distr. Unattended	115	13.8		12	1		Two Stage Fan	1	20
17	South Pullman	Distr. Unattended	115	13.8		24	2		Frcd Air Fan & Capctrs.	240	32
18	Sunset	Distr. Unattended	115	13.8		35	4	1	Portable & Two Stage Fan	4	50
19	Third & Hatch	Distr. Unattended	115	13.8		36	2		Two Stage Fan	2	60
20	Waikiki	Distr. Unattended	115	13.8		24	2		Two Stage Fan		40
21	West Side	Transm. Unattended	230	115	13.8	250	2				
22	Other: 69 substations less than 10MVA	Distr. Unattended				222.5	170	3			
23	STATE OF IDAHO										
24	Appleway	Distr.& Trfr. Unatd	115	13.8		27	4		Portable & Frcd Oil & Air Fan	4	38.8
25	Big Creek	Distr. Unattended	115	13.8		17.5	2				17.5

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
The Washington Water Power Company	(1) [X] An Original (2) [ ] A Resubmission	April 30, 1984	Dec. 31, 1983

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of less than 10,000 Kva, except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).
5. Show in columns (i), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)	Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers in Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (k)
1	Bunker Hill	Distr. Attended	13.8/115	2.3/13.8		23	9	2	Portable Fan	1	25.5
2	Clearwater	Distr. Unattended	115	13.8		65	6	1	Frcd Oil & Air/Two Stage Fan	6	100
3	Coeur d'Alene 15th Ave.	Distr. Unattended	115	13.8		33	4		Frcd Air & Two Stage Fan	4	50
4	Dalton	Distr. Unattended	115	13.8		24	2		Frcd Oil & Air & Two Stage Fan	2	40
5	Grangeville	Distr. & Trfr. Unatd	34/115	13.8		24.5	4		Frcd Oil & Air & Portable Fan	4	34.4
6	Hecla	Distr. Unattended	115	13.8		12	1		Frcd Oil & Air Fan	1	20
7	Holbrook	Distr. Unattended	115	13.8		12	1		Frcd Oil & Air Fan	1	20
8	Jaype	Distr. Unattended	115	13.8		12.5	2				
9	Juliaetta	Distr. Unattended	115	13.8		12	1		Frcd Oil & Air Fan	1	20
10	Kamiah	Distr. & Trfr. Unatd	115	13.8		12	1		Two Stage Fan	1	20
11	Lolo	Transm. & Distr. Unatd	230/115	115/13.8	13.8	257.5	3		Portable Fan	1	259.4
12	Lucky Friday	Distr. Unattended	115	13.8		12			Frcd Air		16
13	Moscow	Distr. Unattended	115	13.8		24	2		Frcd Oil & Air Two Stage Fan	2	40
14	Moscow 230 Kv	Transm. & Distr. Unatd	230/115	115/13.8	13.8	137	2		Capacitors	240	182
15	North Moscow	Distr. Unattended	115	13.8		12	1		Two Stage Fan	1	20
16	Newport	Transm. & Trfr. Unatd	115	60		10	3				
17	North Lewiston	Transm. & Distr. Unatd	230/115	115/13.8		25	1		Frcd Oil & Air Fan	1	280
18	North Lewiston	Distr. Unattended	115	13.8		10	3		Forced Air Fan	3	13
19	Orofino	Distr. Unattended	115	13.8/24		19.5	2		Frcd Oil & Air & Portable Fan	2	29.4
20	Osburn	Distr. Unattended	115	13.8		12	1				
21	Pine Creek	Transm. & Distr. Unatd	230/115	110/13.8	13.8	262	3		Capacitors	240	307
22	Post Falls	Distr. Unattended	115	13.8		12	1		Frcd Oil & Air Fan	1	20
23	Potlatch	Distr. & Trfr. Unatd	115	13.8		19.5	2		Frcd Oil & Air & Frcd Air Fan	2	29.4
24	Smelter Heights	Distr. Unattended	115	13.8		12	1		Frcd Oil & Air Fan	1	20
25	South Lewiston	Distr. Unattended	115	13.8		15	3		Portable Fan	3	18.8

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
The Washington Water Power Company	(1) [X] An Original (2) [ ] A Resubmission	April 30, 1984	Dec. 31, 1983

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of less than 10,000 Kva, except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).
5. Show in columns (i), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Line No.	Name and Location of Substation	Character of Substation	VOLTAGE (In MVa)			Capacity of Substation (In Service) (In MVa)	Number of Transformers in Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT		
			Primary	Secondary	Tertiary				Type of Equipment	Number of Units	Total Capacity
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	Sweetwater	Distr. Unattended	115	24		12	1		Frcd Oil and Air Fan	1	
2	St. Maries	Distr. Unattended	115	24		24	2		Frcd Oil & Air & Two Stage Fan	2	40
3	Tenth & Stewart	Distr. Unattended	115	13.8		24	2		Frcd Oil & Air Fan	2	40
4	Wallace	Distr. & Whsle Unatd	115	13.8		10	3		Portable Fan	3	12.5
5	Rathdrum	Transm. Unattended	115/230	13.8/115	13.8	212	2		Frcd Oil & Air Fan & Capacitors	2&1	26.5
6	Plummer	Distr. & Whsle Unatd	115	13.8		7.5	1		Portable Fan	[illegible]	9.4
7	Other: 37 Substations less than 10 MVA	Distr. Unattended				86.7	57	2			
8	STATE OF MONTANA										
9	1 Substation less than 10 MVA	Distr. Unattended				5	1				
10	SUBSTATIONS AT GENERATING PLANTS:										
11	STATE OF WASHINGTON										
12	Kettle Falls	Trans. Step-Up	115	13.8		30			Frcd Oil & Air Fan	1	50
13	Long Lake	Trans.	115	60	4	78.5	10	1			
14	Nine Mile	Trans. Step-Up & Dist.	115/13.8	60/2.3	2.3	18	3		Portable Fan	2	18.5
15	Little Falls	Trans.	115	60		36	3		Frcd Oil & Air Fan	2	52
16	Meyers Falls	Distr. Step-Up	13.8	11		1.5	3	1	Capacitors	15	1.9
17	Northeast	Trans. Step-Up	115	13.8		36	1		Two Stage Fan	1	60
18	STATE OF IDAHO										
19	Cabinet Gorge	Trans. Step-Up	115	13.8		25	1		Frcd Oil & Air Fan	1	41.7
20	Cabinet Gorge	Trans. Step-Up	230	13.8		255	6	1			
21	Post Falls	Trans. Step-Up	115	2.3		15.8	2		Frcd Air & Oil & Air Fan		19.8
22	STATE OF MONTANA										
23	Noxon	Trans. Step-Up	230	13.8		532.8	9	1			
24											
25											

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
The Washington Water Power Company	(1) [X] An Original (2) [ ] A Resubmission	April 30, 1984	Dec. 31, 1983

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of less than 10,000 Kva, except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. *Indicate in column (b) the functional character* of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).
5. Show in columns (i), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)	Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers in Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (k)
1	Summary:										
2	Washington: 1 sub	Distr. Attend				61					
3	1 sub	Trans. & Distr. Attend				395					
4	6 subs	Transm. Unattend				505.5					
5	107 subs	Distr. Unattend				972.7					
6	5 subs	Trans. & Distr. Unattend				123.5					
7	Idaho: 1 sub	Distr. Attend				23					
8	5 subs	Transm. Unattend				517.8					
9	63 subs	Distr. Unattend				563.7					
10	4 subs	Transm. & Distr, Unattend				681.5					
11	Montana: 1 sub	Transm. Unattend				532.8					
12	1 sub	Distr. Unattend				5					
13	Total System 195 subs					4381.5					
14	The following is not included	in the above listing:									
15											
16	Centralia Plant (1)	Transmission	500		19.1						
17	Near Centralia, WA	Transmission	230		(1)	(1)	(1)				
18											
19	Centralia Switching Sta.										
20	Near Centralia but not										
21	at Centralia Plant (1)	Transmission	(230 switching only)								
22											
23	Paul, C. W., Near Cent. (1)	Transmission	(500 switching only)								
24											
25	(1) Jointly owned. For complete details see FERC Form 1 of Pacific Power & Light Company.										

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
The Washington Water Power Company	(1) [X] An Original (2) [ ] A Resubmission	April 30, 1984	Dec. 31, 19 83

ELECTRIC DISTRIBUTION METERS AND LINE TRANSFORMERS

1. Report below the information called for concerning distribution watt-hour meters and line transformers.
2. Include watt-hour demand distribution meters, but not external demand meters.
3. Show in a footnote the number of distribution watt-hour meters or line transformers held by the respondent under lease from others, jointly owned with others, or held otherwise than by reason of sole ownership by the respondent. If 500 or more meters or line transformers are held under a lease, give name of lessor, date and period of lease, and annual rent. If 500 or more meters or line transformers are held other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of accounting for expenses between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Line No.	Item (a)	Number of Watt Hour Meters (b)	LINE TRANSFORMERS Number (c)	LINE TRANSFORMERS Total Capacity (In MVa) (d)
1	Number at Beginning of Year	See attached	page 427-A.	
2	Additions During Year			
3	Purchases			
4	Associated with Utility Plant Acquired			
5	TOTAL Additions *(Enter Total of lines 3 and 4)*			
6	Reductions During Year			
7	Retirements			
8	Associated with Utility Plant Sold			
9	TOTAL Reductions *(Enter Total of lines 7 and 8)*			
10	Number at End of Year *(Lines 1 + 5 - 9)*			
11	In Stock			
12	Locked Meters on Customers' Premises			
13	Inactive Transformers on System			
14	In Customers' Use			
15	In Company's Use			
16	TOTAL End of Year *(Enter Total of lines 11 to 15. This line should equal line 10.)*			

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THE WASHINGTON WATER POWER COMPANY
ELECTRIC DISTRIBUTION METERS AND LINE TRANSFORMERS
Page 427-A
Year Ended December 31, 1983

	ELECTRIC WATT-HOUR METERS			LINE TRANSFORMERS					
				State of Washington		State of Idaho		Total System	
Item	Washington	Idaho	Total System	Number	Total Capacity (Mva)	Number	Total Capacity (Mva)	Number	Total Capacity (Mva)
Number at beginning of year	180,924	73,031	253,955	53,955	1,987	25,644	852	79,599	2,839
Acquired during year	12,944	3,172	16,116	2,184	95	482	15	2,666	110
Transferred between states	2,807	1,354	4,161	384	13	351	20	735	33
Total	196,675	77,557	274,232	56,523	2,095	26,477	887	83,000	2,982
Retired during year	13,262	259	13,521	1,167	35	-	-	1,167	35
Transferred between states	(1,354)	(2,807)	(4,161)	(351)	(20)	(384)	(13)	(735)	(33)
Number at End of Year	182,059	74,491	256,550	55,005	2,040	26,093	874	81,098	2,914
In stock	3,055	650	3,705	1,783	109	457	21	2,240	130
In customer's and Company's use	179,004	73,841	252,845	53,222	1,931	25,636	853	78,858	2,784
Total End of Year (As Above)	182,059	74,491	256,550	55,005	2,040	26,093	874	81,098	2,914

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
The Washington Water Power Company	(1) [X] An Original (2) [ ] A Resubmission	April 30, 1984	Dec. 31, 19 83

ENVIRONMENTAL PROTECTION FACILITIES

1. For purposes of this response, environmental protection facilities shall be defined as any building, structure, equipment, facility, or improvement designed and constructed solely for control, reduction, prevention or abatement of discharges or releases into the environment of gaseous, liquid, or solid substances, heat, noise or for the control, reduction, prevention, or abatement of any other adverse impact of an activity on the environment.

2. Report the differences in cost of facilities installed for environmental considerations over the cost of alternative facilities which would otherwise be used without environmental considerations. Use the best engineering design achievable without environmental restrictions as the basis for determining costs without environmental considerations. It is not intended that special design studies be made for purposes of this response. Base the response on the best engineering judgement where direct comparisons are not available.

Include in these differences in costs the costs or estimated costs of environmental protection facilities in service, constructed or modified in connection with the production, transmission, and distribution of electrical energy and shall be reported herein for all such environmental facilities placed in service on or after January 1, 1969, so long as it is readily determinable that such facilities were constructed or modified for environmental rather than operational purposes. Also report similar expenditures for environmental plant included in construction work in progress. Estimate the cost of facilities when the original cost is not available or facilities are jointly owned with another utility, provided the respondent explains the basis of such estimations.

Examples of these costs would include a portion of the costs of tall smokestacks, underground lines, and landscaped substations. Explain such costs in a footnote.

3. In the cost of facilities reported on this page, include an estimated portion of the cost of plant that is or will be used to provide power to operate associated environmental protection facilities. These costs may be estimated on a percentage of plant basis. Explain such estimations in a footnote.

4. Report all costs under the major classifications provided below and include, as a minimum, the items listed hereunder:

A. Air pollution control facilities:
   (1) Scrubbers, precipitators, tall smokestacks, etc.
   (2) Changes necessary to accommodate use of environmentally clean fuels such as low ash or low sulfur fuels including storage and handling equipment
   (3) Monitoring equipment
   (4) Other

B. Water pollution control facilities:
   (1) Cooling towers, ponds, piping, pumps, etc.
   (2) Waste water treatment equipment
   (3) Sanitary waste disposal equipment
   (4) Oil interceptors
   (5) Sediment control facilities
   (6) Monitoring equipment
   (7) Other.

C. Solid waste disposal costs:
   (1) Ash handling and disposal equipment
   (2) Land
   (3) Settling ponds
   (4) Other.

D. Noise abatement equipment:
   (1) Structures
   (2) Mufflers
   (3) Sound proofing equipment
   (4) Monitoring equipment
   (5) Other

E. Esthetic costs:
   (1) Architectural costs
   (2) Towers
   (3) Underground lines
   (4) Landscaping
   (5) Other.

F. Additional plant capacity necessary due to restricted output from existing facilities, or addition of pollution control facilities.

G. Miscellaneous.
   (1) Preparation of environmental reports
   (2) Fish and wildlife plants included in Accounts 330, 331, 332, and 335.
   (3) Parks and related facilities
   (4) Other.

5. In those instances when costs are composites of both actual supportable costs and estimates of costs, specify in column (g) the actual costs that are included in column (f).

6. Report construction work in progress relating to environmental facilities at line 9.

Line No.	Classification of Cost (a)	Balance at Beginning of Year (b)	Changes During Year: Additions (c)	Changes During Year: Retirements (d)	Changes During Year: Adjustments (e)	Balance at End of Year (f)	Actual Cost (g)
1	Air Pollution Control Facilities	9,169,180	4,071,756			13,240,936	
2	Water Pollution Control Facilities	1,021,600	2,829,189			3,850,789	
3	Solid Waste Disposal Costs	177,662				177,662	
4	Noise Abatement Equipment	46,090				46,090	
5	Esthetic Costs	3,635,800	292,243			3,928,043	
6	Additional Plant Capacity	554,200	330			554,530	
7	Miscellaneous (Identify significant)	107,010	181,318 (1)			288,328	
8	TOTAL (Total of lines 1 thru 7)	14,711,542	7,374,836			22,086,378	
9	Construction Work in Progress	58,241,714				74,191,700	

Note: (1) Recreational Park at Post Falls, Idaho.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
The Washington Water Power Company	(1) [X] An Original (2) [ ] A Resubmission	April 30, 1984	Dec. 31, 19 83

ENVIRONMENTAL PROTECTION EXPENSES

1. Show below expenses incurred in connection with the use of environmental protection facilities, the cost of which are reported on page 428. Where it is necessary that allocations and/or estimates of costs be made, state the basis or method used.

2. Include below the costs incurred due to the operation of environmental protection equipment, facilities, and programs.

3. Report expenses under the subheadings listed below.

4. Under item 6 report the difference in cost between environmentally clean fuels and the alternative fuels that would otherwise be used and are available for use.

5. Under item 7 include the cost of replacement power, purchased or generated, to compensate for the deficiency in output from existing plants due to the addition of pollution control equipment, use of alternate environmentally preferable fuels, or environmental regulations of governmental bodies. Base the price of replacement power purchased on the average system price of purchased power if the actual cost of such replacement power is not known. Price internally generated replacement power at the system average cost of power generated if the actual cost of specific replacement generation is not known.

6. Under item 8 include ad valorem and other taxes assessed directly on or directly relatable to environmental facilities. Also include under item 8 licensing and similar fees on such facilities.

7. In those instances where expenses are composed of both actual supportable data and estimates of costs, specify in column (c) the actual expenses that are included in column (b).

Line No.	Classification of Expense *(a)*	Amount *(b)*	Actual Expenses *(c)*
1	Depreciation	392,901	
2	Labor, Maintenance, Materials, and Supplies Cost Related to Env. Facilities and Programs	85,425	
3	Fuel Related Costs		
4	Operation of Facilities	96,592	
5	Fly Ash and Sulfur Sludge Removal	192,718	
6	Difference in Cost of Environmentally Clean Fuels		
7	Replacement Power Costs	169,360	
8	Taxes and Fees	102,995	
9	Administrative and General	10,593	
10	Other *(Identify significant)*		
11	TOTAL	1,050,584	

Attachment 5-4
Forecasts and Backcasts of Average System Costs and Loads for FY 2002 Through 2008
WP-07-E-BPA-83
Page 300

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
The Washington Water Power Company	(1) [X] An Original (2) [ ] A Resubmission	April 30, 1984	Dec. 31, 19 83

FOOTNOTE DATA

Page Number (a)	Item Number (b)	Column Number (c)	Comments (d)
202	7	a	Steam Production Plant additions consist primarily of the Kettle Falls Project placed in service on December 1, 1983. Included therein are Construction Work in Progress credits which have not been classified for test power of:
402	2-11	b	Jointly owned. Installed capacity on Line 5 represents only Respondent's 15% share. Please refer to Form 1 of Pacific Power and Light Company.
403	40-43	d	An availability charge of $25,000.00 per month has been excluded for purposes of calculating cost of fuel.
403	12	e	Includes 22,565,000 Kwh's of test generation for which operating expenses are not reflected in Total Production Expenses.
403	36	e	Natural Gas was used as a start-up fuel during initial start-up for which no operating expenses are reflected in 1983.

Account No.	Description	Amount
311	Structures and Improvements	$(137,060)
312	Boiler Plant Equipment	(280,037)
314	Turbogenerator Units	(94,928)
315	Accessory Electric Equipment	(61,059)
316	Misc. Power Plant Equipment	(12,891)
	Total	$(585,975)

Attachment 5-4
Forecasts and Backcasts of Average System Costs and Loads for FY 2002 Through 2008
WP-07-E-BPA-83

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INDEX (Continued)

INDEX (Continued)

INDEX (Continued)

Schedule — Page No.

Puget Sound Energy ASC Docket Number 7-A2-9501 | **Puget Sound Energy 1997 FERC Form 1 Data**

	ASC Total	ASC Production	ASC Transmission	ASC Distribution	FERC Total	FERC Production	FERC Transmission	FERC Distribution
Rate Base								
Total Plant In-Service	3,181,388	951,120	423,460	1,806,808	3,384,516	999,542	509,631	1,875,343
Less Accumulated Depreciation	1,002,601	264,663	133,900	604,038	1,188,576	390,809	147,031	650,737
Total Net Plant In-Service	2,178,787	686,456	289,561	1,202,770	2,195,940	608,734	362,600	1,224,607
Other Rate Base	-	-	-	-	172,511	32,369	13,654	126,489
Deferred Assets	449,363	300,088	17,143	132,132	569,634	156,840	5,425	407,369
Deferred Liabilities	275,229	306	137	274,787	627,066	24,191	5,497	597,378
Net Rate Base	2,352,920	986,239	306,567	1,060,115	2,311,019	773,752	376,181	1,161,086
Operating and Maintenance Costs								
Production	574,104	573,942	-	162	506,463	506,463	0	0
Transmission	50,702	-	49,874	829	40,520	-	39,287	1,232
Distribution	39,300	-	-	39,300	45,614	0	0	45,614
Total Customer & Sales Expense	56,378	29,953	(90)	26,515	29,071	0	0	29,071
Administration & General	64,797	7,141	3,084	54,573	65,430	13,641	7,731	44,058
Total Operations & Main	785,282	611,036	52,867	121,379	687,098	520,104	47,019	119,975
Depreciation & Amortization	108,785	30,879	12,186	65,720	99,250	30,256	16,036	52,957
Taxes	166,320	10,955	4,876	150,489	222,386	19,987	4,761	197,638
Total Costs	1,060,386	652,870	69,929	337,588	1,008,734	570,347	67,816	370,570
Sales for Resale	64,931	64,931	-	-	72,847	72,847	0	0
Other Revenues	23,418	6,310	5,982	11,126	(86,862)	0	(101,021)	14,159
Total Other Included Items	88,349	71,241	5,982	11,126	(14,015)	72,847	(101,021)	14,159
Net Costs	972,037	581,630	63,946	326,461	1,022,748	497,500	168,837	356,411

Puget Sound Energy ASC Docket Number 7-A2-9501

	Total	Production	Transmission	Distribution
Cost Adjustments	-	-	-	-
Revenue Adjustments	-	-	-	-
Total Operating Expenses	972,037	581,630	63,946	326,461
Return on Rate Base @ 7.93%	186,589	78,110	24,280	84,199
Total Contract System Costs	1,158,626	659,740	88,226	410,660
Exchange Costs	747,966			
Total Contract System Load	20,473			
Average System Cost $/MWh	36.53			
ASC $/MWh Differential	$ (0.67)			
Percent Differential	-1.82%			

Puget Sound Energy 1997 FERC Form 1 Data

	Total	Production	Transmission	Distribution
Total Operating Expenses	1,022,748	497,500	168,837	356,411
Return on Rate Base	193,462	64,773	31,491	97,198
Total Contract System Costs	1,216,210	562,273	200,328	453,609
Exchange Costs	762,601			
Total Contract System Load	21,261			
Average System Cost $/MWh	35.87			

PacifiCorp Oregon ASC Docket Number 5-A1-9601 | **PacifiCorp Oregon 1997 FERC Form 1 Data**

	ASC Total	ASC Production	ASC Transmission	ASC Distribution	FERC Total	FERC Production	FERC Transmission	FERC Distribution
Rate Base								
Total Plant In-Service	3,565,605	1,763,111	507,019	1,295,475	3,289,739	1,592,472	479,119	1,218,147
Less Accumulated Depreciation	1,121,552	651,753	173,107	296,693	1,223,803	633,323	164,839	425,640
Total Net Plant In-Service	2,444,053	1,111,358	333,912	998,782	2,065,936	959,149	314,280	792,507
Other Rate Base	143,039	76,155	6,451	60,433	205,801	87,851	11,588	106,363
Deferred Assets	37,119	21,030	-	16,089	349,503	178,365	7,859	163,279
Deferred Liabilities	238,221	12,958	268	224,995	463,243	41,194	6,443	415,606
Net Rate Base	2,385,990	1,195,585	340,095	850,309	2,157,998	1,184,171	327,285	646,542
Operating and Maintenance Costs								
Production	335,514	335,514	-	-	548,387	548,387	0	0
Transmission	23,877	-	22,401	1,476	26,664	-	25,276	1,388
Distribution	30,121	-	-	30,121	32,410	0	0	32,410
Total Customer & Sales Expense	26,780	4,506	-	22,274	37,722	0	0	37,722
Administration & General	51,883	20,929	2,762	28,191	121,048	58,283	10,191	52,573
Total Operations & Main	468,175	360,949	25,163	82,062	766,230	606,670	35,467	124,093
Depreciation & Amortization	102,040	44,596	12,799	44,645	104,131	44,522	13,463	46,146
Taxes	119,255	12,674	3,728	102,853	104,863	15,058	3,185	84,902
Total Costs	689,470	418,219	41,690	229,560	975,224	666,250	52,116	255,140
Sales for Resale	178,773	178,773	-	-	412,810	412,810	0	0
Other Revenues	14,306	10,539	302	3,465	23,017	0	17,215	5,801
Total Other Included Items	193,079	189,312	302	3,465	435,827	412,810	17,215	5,801
Net Costs	496,391	228,907	41,388	226,095	539,397	253,440	34,900	249,339

PacifiCorp Oregon ASC Docket Number 5-A1-9601	Total	Production	Transmission	Distribution	PacifiCorp Oregon 1997 FERC Form 1 Data Total	Production	Transmission	Distribution
Cost Adjustments	18,656	-	-	18,656	(153)	(71)	(23)	(59)
Revenue Adjustments	(3,519)	(1,929)		(1,593)				
Total Operating Expenses	511,528	226,978	41,388	243,158	539,244	253,369	34,877	249,280
Return on Rate Base @ 7.64%	182,290	91,343	25,983	64,964	104,553	77,250	21,351	42,178
Total Contract System Costs	693,818	318,321	67,371	308,122	643,796	330,619	56,228	291,457
Exchange Costs	385,692				386,847			
Total Contract System Load	14,286				14,356			
Average System Cost $/MWh	27.00				26.95			
ASC $/MWh Differential	$ (0.05)							
Percent Differential	-0.19%							

Request Detail

Request ID: BPA-JP17-3
Page Number: 35
Line Number: 9-23
Exhibit Filing: WP-07-E-JP17-1

Contact Name: Paul McClain
Contact Phone: 503.230.7384
Contact Email: pwtmcclain@bpa.gov

Request Text: DATA REQUEST: Please provide all work papers, models, Cookbook models, studies and analysis to support the 2002 – 2006 "PCA ASC" calculations. Include all the costs that would populate the ASC Cookbook Model, to include all rate base accounts, O&M costs, depreciation expense, exchangeable taxes, and revenue credits.

Response Detail

Date Response Filed: 4/17/2008 2:55:07 PM
Contact Name: Don Schoenbeck
Contact Phone: 360.737.3877
Contact Email: dws@r-c-s-inc.com
Response Text:
As noted in the testimony, the "PCA ASCs" are simply the base power costs approved by the WUTC in the seven dockets changing PSE's rates from 2002 through 2007. These values were used as a proxy for the backcast ASCs that should have been derived pursuant to the 1984 ASCM. This is particularly important with regard to PSE as the WUTC has disallowed portions of purchase power commitments. These disallowances would not be reflected in FERC Form 1 filings. The attached EXCEL file indicates the WUTC docket number, effective date and the base power cost for each of the seven rate changes. The "PCA ASC" was derived simply using the number of days the base power cost was in place during each of BPA's fiscal years.

Portland General Electric

Summary of 2002 FERC Form 1 Based ASC Filing

Source: Table 7.5.1 Portland General Electric 2002

WP-07-E-BPA-44A - Page 643 to 654

	Production	Transmission	Contract System Cost
Total Operating Expenses	$877,995,940	$78,341,521	$956,337,461
Return on Rate Base	63,886,011	15,300,726	79,186,737
Total Cost	$941,881,951	$93,642,247	**$1,035,524,198**
Total Retail Load	18,771,884		
Distribution Losses	938,594		
Contract System Load	19,710,478		
Average System Cost	**$52.54**		
Production Total Operating Expenses	**$877,995,940**		
less non-PCA related costs			
Allocated A&G	$32,529,926		
Depreciation & Amortization	55,067,302		
Allocated Taxes	20,746,221		
BPA REP Reversal	15,239,610		
Oregon Public Purpose Charge	15,989,160		
Non-Power costs	**$139,572,219**		
Total Power Costs	$738,423,721	$37.46	
Cowlitz-Clark "Benchmark" ASC		$37.40	
Percentage Differential		0.170%	

Request Detail

Request ID: BPA-JP17-7
Page Number: 37
Line Number: 21-24
Exhibit Filing: WP-07-E-JP17-1

Contact Name: Paul McClain
Contact Phone: 503.230.5489
Contact Email: pwtmcclain@bpa.gov

Request Text: Were Cowlitz County PUD or Clark Public Utilities represented in the WP-07 rate proceeding, either individually or as a member of a group, trade association, or other entity? If so, did Cowlitz County PUD, Clark Public Utilities or, if applicable, any group or association representing them, offer direct testimony or rebuttal testimony that addressed the testimony of Boling, Doubleday and McClain, WP-07-E-BPA-16, page 9, lines 2 - 19?

Response Detail

Date Response Filed: 4/17/2008 2:59:51 PM
Contact Name: Don Schoenbeck
Contact Phone: 360.737.3877
Contact Email: dws@r-c-s-inc.com
Response Text:
Yes, Cowlitz and Clark were represented in the WP-07 rate proceeding. Clark participated as part of the Western Public Agencies Group (WPAG). Cowlitz and WPAG representatives offered no direct testimony that addressed WP-07-E-BPA-16, page 9, lines 2 -19.

Request Detail

Request ID: BPA-WA-24
Page Number: 44
Line Number: 1-5
Exhibit Filing: WP-07-E-WA-01

Contact Name: Paul McClain
Contact Phone: 503.230.5489
Contact Email: pwtmcclain@bpa.gov

Request Text: Did the Western Public Agencies Group, or any of its members, intervene in the original WP-07 rate filing? If so, did any witnesses representing WPAG or any of its members offer direct testimony or rebuttal testimony that addressed BPA's testimony of Boling, Doubleday and McClain, WP-07-E-BPA-16, page 9, lines 2 - 19?

Response Detail

Date Response Filed: 4/18/2008 1:55:07 PM
Contact Name:
Contact Phone:
Contact Email:
Response Text:
WPAG did intervene in the original WP-07 rate filing, but did not offer direct testimony or rebuttal testimony that addressed the referenced section of testimony.

Request Detail

Request ID: BPA-JP17-4
Page Number: 35
Line Number: 9-23
Exhibit Filing: WP-07-E-JP17-1

Contact Name: Paul McClain
Contact Phone: 503.230.5489
Contact Email: pwtmcclain@bpa.gov

Request Text: DATA REQUEST: In your review of Puget Sound Energy (PSE) rate cases, did you review any of its general rate cases during the 2002 – 2006 period? If so, please provide docket number and copies of any final rate orders.

Response Detail

Date Response Filed: 4/17/2008 2:55:54 PM
Contact Name: Don Schoenbeck
Contact Phone: 360.737.3877
Contact Email: dws@r-c-s-inc.com
Response Text:
Mr. Schoenbeck provided consulting services to a PSE customer group for all seven of the WUTC dockets listed in the EXCEL file provided in response to BPA-JP17-3. Three of the docket numbers were for general rate cases (011570, 040641 and 060266) with the remaining dockets being "power cost only" rate cases. The WUTC orders associated with these proceedings (and other documents) can be readily obtained by doing a search of the WUTC web site using the six digit docket number.

2002-2006 Lookback Analysis
PUC Orders that Changed Rates

Idaho Public Utilities Commission

Avista Utilities	**Order Date**
1. Avoided Cost Rates	July 2002
2. Power Cost Adjustment	October 2002
3. Power Cost Adjustment	October 2003
4. Avoided Cost Rates	December 2003
5. General Rate Case	October 2004
6. Power Cost Adjustment	October 2004
7. Coyote Springs 2 Case	April 2005
8. Power Cost Adjustment	October 2005
9. Cogeneration Rates	August 2006
10. Power Cost Adjustment	October 2006
11. Elimination of Centralia Gain	October 2006
Idaho Power	
12. Power Cost Adjustment	May 2002
13. Avoided Cost Rates	July 2002
14. Power Cost Adjustment	June 2003
15. Avoided Cost Rates	December 2003
16. Power Cost Adjustment	May 2004
17. Avoided Cost Rates	December 2004
18. Rate Change Taxes	May 2005
19. General Rate Case	May 2005
20. Power Cost Adjustment	May 2005
21. General Rate Case	May 2006
22. Power Cost Adjustment	May 2006
PacifiCorp	
23. Irrigation Rates Credit	March 2003
24. Irrigation Rates Credit	January 2004
25. Qualifying Facilities Rate	June 2004
26. General Rate Case	July 2005
27. DSM Surcharge	May 2006
28. Rate Change	December 2007

Washington Utilities and Transportation Commission

Avista Utilities	Order Date
29. General Rate Case	January 2002
30. Avoided Cost Rates	November 2002
31. Low Income Assistance Surcharge	April 2004
32. Avoided Cost Rates	November 20005
33. General Rate Case	December 2005
34. Renewable Purchase Rates	September 2006
35. Public Purpose Rider Change	October 2006
36. Avoided Cost Rates	November 2006

PacifiCorp

37. Increase System Benefits Charge	Feb 2002
38. Tariff Revisions	April 2004
39. Low Income Assistance Surcharge	July 2004
40. Cancel Scottish Power Credit	September 2004
41. General Rate Case	October 2004
42. Increase System Benefits Charge	February 2005
43. Energy Efficiency Tariffs	April 2005
44. Centralia Credit	June 2005
45. Rate Refund	August 2005
46. System Benefit Charge	November 2006
47. Avoided Cost Rates	December 2006

Puget

48. General Rate Case	June 2002
49. Conservation Rates	November 2002
50. Conservation Rates	December 2003
51. Power Cost Adjustment	May 2004
52. Conservation Rider Changes	July 2004
53. General Rate Case	February 2005
54. Line Extension Rates	March 2005
55. Implement Schedule 40 Tariff	March 2005
56. Minor Tariff Changes	April 2005
57. Green Energy Rates	May 2005
58. Income Tax Rider	July 2005
59. Low Income Tariff	September 2005
60. Power Cost Adjustment	November 2005
61. Line Extension Rates	March 2006
62. Residential Tariff Added	June 2006
63. Conservation Rates	August 2006
64. Low Income Tariff	September 2006
65. Municipal Tax Tariff	November 2006

Oregon Public Utilities Commission

PacifiCorp

66. Power Cost Adjustment	March 2003
67. Rate Change	May 2003
68. Rate Change	December 2003
69. Rate Refund	May 2004
70. General Rate Case	September 2006

Idaho Power

71. Power Cost Adjustment	August 2002
72. Power Cost Adjustment	April 2004
73. General Rate Case	July 2005

Portland General Electric

74. Renewable Tariff	October 2002
75. Power Cost Adjustment	December 2002
76. Surge Protector Tariff Filing	December 2003
77. Standby Tariff Filing	July 2004

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2007 Supplemental Wholesale Power Rate Case Initial Proposal

REBUTTAL TESTIMONY

SLICE RATE AND REVENUE REQUIREMENT

May 2008

WP-07-E-BPA-84

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INDEX

REBUTTAL TESTIMONY of

CARIE E. LEE, RONALD J. HOMENICK, and JANICE A. JOHNSON

Witnesses for Bonneville Power Administration

SUBJECT: SLICE RATE AND REVENUE REQUIREMENT

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REBUTTAL TESTIMONY of

CARIE E. LEE, RONALD J. HOMENICK, and JANICE A. JOHNSON

Witnesses for Bonneville Power Administration

SUBJECT: SLICE RATE AND REVENUE REQUIREMENT

Section 1: Introduction and Purpose of Testimony

Q. Please state your names and qualifications.

A. My name is Carie E. Lee and my qualifications are contained in WP-07-Q-BPA-28.

A. My name is Ronald J. Homenick and my qualifications are contained in WP-07-Q-BPA-17.

A. My name is Janice A. Johnson and my qualifications are contained in WP-07-Q-BPA-63.

Q. Have you sponsored testimony previously in this Supplemental Proceeding?

A. Yes. Ms. Lee, Mr. Homenick and Ms. Johnson have submitted direct testimony, with another witness, identified as exhibits WP-07-E-BPA-59 and WP-07-E-BPA-74. Mr. Homenick has submitted direct testimony, with other witnesses, identified as exhibits WP-07-E-BPA-55, WP-07-E-BPA-58, WP-07-E-BPA-65, WP-07-E-BPA-70, and WP-07-E-BPA-75.

Q. Please state the purpose of your testimony.

A. The purpose of this testimony is to respond to direct testimony filed by the Slice Customers Group, WP-07-E-JP22-1, regarding the Slice Rate and revenue requirement.

Q. How is your testimony organized?

A. This testimony consists of five sections. Section 1 explains the purpose and scope of the testimony. Sections 2 through 6 of this testimony follow the same order and content of the sections contained in the direct testimony of the Slice Customers Group. Section 2 discusses the Slice Customers Group's proposal to view the FY 2007-2009 rate period as a split rate period. Section 3 discusses BPA's treatment of the Reduction of Risk

Discount expense. Section 4 discusses items that BPA does not true up in the Slice Product Costing and True-Up Table. Section 5 discusses the Lookback treatment of the Slice Customer Payments.

Section 2: Use of a Split Rate Period

Q. Instead of using the average of the Slice Revenue Requirement for the three years of the rate period as the basis for the Slice Rate for FY 2009 as BPA proposes, the Slice Customers Group proposes that the Slice Rate for FY 2009 be based only on the "new (lower) FY 2009 revenue requirement … approved in the WP-07 Supplemental Rate Case." Brawley and Gregg, WP-07-E-JP22-1 at 3. Do you agree with the Slice Customers' proposal?

A. We do not agree with the Slice Customers Group's proposal that the Slice Rate for FY 2009 should be based only on the "new (lower) FY 2009 revenue requirement."

The Supplemental Proposal reopens the WP-07 rate proceeding, which applies to the rate period FY 2007-2009. *See* Lefler, *et al.*, WP-07-E-BPA-63. We are not proposing to establish a single-year rate period only for FY 2009. The Slice Rate Methodology states that the Slice Rate and the Slice True-Up are based on the average annual Slice Revenue Requirement for the applicable rate period. *See* Supplemental Wholesale Power Rate Schedules and GRSPs, WP-07-E-BPA-51, FY 2002-2011 Slice Rate Methodology, Appendix A, at 134-137. Because the applicable rate period is FY 2007-2009, the Slice Rate will be based on the average annual Slice Revenue Requirement for FY 2007-2009, and not just on the Slice Revenue Requirement for FY 2009.

Furthermore, the Slice Settlement Agreement (07PB-12273) directs BPA to base the Slice True-Up on the annual average Slice Revenue Requirement for the rate period. Therefore, we cannot arbitrarily separate the effective rate period into two distinct parts.

To do so would be inconsistent with the terms of the Slice Settlement Agreement. The Slice Settlement Agreement resolved issues in then-pending litigation in the Ninth Circuit: *Northwest Requirements Utilities, et al. v. Bonneville Power Administration,* No. 03-73849; *Northwest Requirements Utilities v. Bonneville Power Administration,* No. 04-71311; and *Benton County PUD, et al. v. Bonneville Power Administration,* No. 03-74179. The Slice Settlement Agreement provision regarding the annual average Slice Revenue Requirement for the rate period is binding on BPA and the Slice Customers Group for the term of the current Slice contract. Absent a formal modification of the Slice Settlement Agreement, BPA, as well as the Slice Customers Group, is bound by this decision to base the Slice True-Up on the annual average Slice Revenue Requirement for the rate period, rather than the Slice Revenue Requirement for an individual year.

Q. In a data response, the Slice Customers Group states that Slice customers should pay, for the entirety of FY 2008, the Slice Rate that is based on a three-year average Slice Revenue Requirement established in the WP-07 Wholesale Power Rate Case, and that it should be trued-up for FY 2008 to the three-year average Slice Revenue Requirement established in the WP-07 Wholesale Power Rate Case. See Data Response BPA-JP22-2, Attachment 1 to this testimony. The Slice Customers Group states that this is its "preferred approach." Id. Please respond.

A. We agree that the Slice customers should pay, for the entirety of FY 2008, the Slice Rate that is based on the three-year average Slice Revenue Requirement established in the WP-07 Wholesale Power Rate Case, and that they should be Trued-Up for FY 2008 to the three-year average Slice Revenue Requirement established in the WP-07 Wholesale Power Rate Case.

Section 3: Treatment of Reduction of Risk Discount

Q. The Slice Customers Group states that in making corrections to the FY 2009 revenue requirements, BPA eliminated the IOU Reduction of Risk Discount, an amount of $23.024 million. Although the Slice Customers Group believes BPA eliminated the cost for FY 2009, they contend BPA has not made similar provisions to return any comparable charges for FY 2007 or FY 2008. Brawley and Gregg, WP-07-E-JP22-1 at 4. How do you respond?

A. We eliminated the IOU Reduction of Risk Discount ($23.024 million) from line 135 in the Slice Product Costing and True-Up Table for FY 2009. *See* Lee, *et al.*, WP-07-E-BPA-74, Table 1 at 2. However, we do not agree that we failed to make similar provisions to return the IOU Reduction of Risk Discount amounts for FY 2007 and FY 2008 to Slice customers.

We stated that we would return any FY 2007-2008 IOU Reduction of Risk Discount amounts in a manner consistent with the policy guidance given in Bliven, *et al*., WP-07-E-BPA-52. *See* Marks, *et al*., WP-07-E-BPA-62 at 17. We assume that payments made under the Reduction of Risk provision are not provided the protection afforded to the Load Reduction Agreements (LRAs) and that such amounts received by the IOUs from the Reduction of Risk Discount will be returned to the Consumer-Owned Utilities (COUs). *Id.*

Q. How will the amounts received by the IOUs from the Reduction of Risk Discount be returned to the COUs?

A. BPA will return overcharges to the COUs for FY 2007 and FY 2008 through lump sum payments in FY 2008 and/or FY 2009. *See* Marks, *et al*., WP-07-E-BPA-62 at 22. How a COU is paid differs, depending on whether or not a COU has entered into a Standstill Agreement. *Id.* at 23.

Q. Please explain how Slice customers who enter into Standstill Agreements will be paid.

A. Slice customers who enter into Standstill Agreements will receive an initial Standstill Payment in spring, 2008 and a subsequent True-Up payment. Marks, *et al*., WP-07-E-BPA-62 at 24. The Standstill and true-up payments would then be reconciled with the Slice True-Up so payments "work the same" for both categories of payments (Standstill and True-Up payments) to COUs that have entered into Standstill Agreements (emphasis added). *Id.* at 24. The intent of the words "work the same" was that the operation of the Slice True-Up for FY 2008 would not alter the amounts of Standstill and True-Up payments to COUs that have entered into Standstill Agreements.

Q. Please explain how Slice customers who do not enter into Standstill Agreements will be paid.

A. The Slice Customer Payment Amounts, plus interest, will be reflected in the FY 2008 Slice True-Up. Marks, *et al*., WP-07-E-BPA-62 at 26. This means the Slice Customer Payment Amounts, plus interest, will be credited to Slice customers through their FY 2008 Slice True-Up Adjustment Charge. The operation of the Slice True-Up for FY 2008 would not alter the amounts of Slice Customer Payment Amounts, plus interest, that were due to the Slice customer.

Q. Will Slice customers that signed Standstill Agreements and Slice customers that do not enter into Standstill Agreements both receive compensation for amounts associated with the Reduction of Risk Discount?

A. Yes.

Q. The Slice Customers Group states that in the original WP-07 rate case, BPA concluded that the expense for the Reduction of Risk Discount was a payment established by contract and therefore not subject to the Slice True-Up. Brawley and Gregg, WP-07-E-JP22-1 at 5. This determination has prevented BPA from using the Slice True-Up as a convenient method of returning the funds. Id. BPA has not provided any other alternatives. Id. Do you agree with these statements?

A. We agree that the WP-07 Wholesale Power Rate Case determined that the expense for the Reduction of Risk Discount ("deferred" augmentation expense) was not subject to the Slice True-Up. *See* Lee, *et al.*, WP-07-E-BPA-23 at 10. However, we do not agree that we have not provided any other alternatives.

. In the absence of Standstill Agreements, we propose to make adjustments either through adjustments to future Slice rates or using the Slice True-Up process in a manner commensurate with the adjustments made to non-Slice rates to account for these FY 2007 and FY 2008 expense reductions. *See* Johnson, *et al.,* WP-07-E-BPA-59 at 6. This means that Slice customers will receive any adjustments that non-Slice customers receive. If non-Slice customers receive adjustments related to the Reduction of Risk Discount, then Slice customers will receive adjustments in a fashion comparable to the non-Slice customers. If Standstill Agreements are signed, we propose to compensate Slice customers who sign such Agreements for adjustments related to the Reduction of Risk Discount. As described previously, the Slice True-Up for FY 2008 will not alter the amounts of Standstill and True-Up payments that are due to the Slice customer signing the Standstill Agreements, nor will it alter the Slice Customer Payment Amounts, plus interest, that are due to the Slice customers who do not sign the Standstill Agreements. BPA would also ensure that the operation of the Slice True-Up for FY 2008 will not result in double payments to Slice customers who sign the Standstill Agreements.

Q. The Slice Customers Group recommends that the Slice customers receive their shares (collectively, 22.6278 percent of the $46.048 million paid by PF customers in FY 2007 - 2008) in a lump sum payment with their respective shares of the Reduction of Risk Discount return. Brawley and Gregg, WP-07-E-BPA-JP22-1 at 5. In Data Response BPA-JP22-3, the Slice Customers Group clarified that the lump sum payment correction associated with both FY 2007 and FY 2008, which they recommended, should be made as part of the FY 2008 Slice True-Up. Do you agree?

A. We agree with the Slice Customers Group's recommendation that a lump sum payment correction associated with both FY 2007 and FY 2008 should be made as part of the FY 2008 Slice True-Up. The FY 2008 Slice True-Up will reflect the reduction of the $46.048 million paid by PF customers in FY 2007-2008 by crediting each Slice customer for its proportionate share of the reduction in this expense through the Individual Credits mechanism that is part of the Slice True-Up process. *See* Section 4 below. We would also ensure that the operation of the Slice True-Up for FY 2008 would not result in double payments to Slice customers who sign the Standstill Agreements – once through the Standstill and related true-up payments and again through the Slice True-Up for FY 2008.

Section 4: Items BPA Does Not True-Up in the Slice Product Costing and True-Up Table

Q. The Slice Customers Group states that in past rate cases, BPA has taken the position that it can exempt some costs from being trued up in the annual Slice True-Up process. Brawley and Gregg, WP-07-E-BPA-JP22-1 at 5. The Slice Customers Group further states that Other Augmentation expenses and related revenue credits should be trued up because energy need and the price forecasts used to determine the Other Augmentation expenses and related revenue credits are speculative by nature and as such, should be corrected to actual costs or prices in the annual Slice True-Up. Id. at 6. Do you agree?

A. We do not believe that we can or should true up the augmentation power expense. In the WP-07 Final Proposal, BPA stated that the net cost of augmentation power for FY 2007-2009 was not subject to the Slice True-Up process. *See* Lee, *et al.*, WP-07-E-BPA-23 at 11. In addition, BPA, along with many Slice customers, non-Slice customers, IOUs, and tribal entities, signed the Partial Resolution of Issues, which addressed, among other things, whether augmentation expenses would be subject to the Slice True-Up. *See* WP-07 Administrator's Final Record of Decision, Partial Resolution of Issues, Attachment A, Section 6.c.iii; Evans, *et al*., WP-07-E-BPA-31 at A-5. The Partial Resolution of Issues specifically provided that the net cost of augmentation would not be trued up to actual costs. None of the utilities that comprise the Slice Customers Group opposed the Partial Resolution of Issues, and many within the group filed testimony in support of the specific section that includes the resolution of the augmentation issue. Those members of the Slice Customers Group specifically supporting this treatment of augmentation included PNGC, Franklin Co. PUD, Grays Harbor Co. PUD, Pend Oreille Co. PUD, and Eugene Water and Electric Board. *See* Brawley, *et al*., WP-07-E-JP11-02 at 1-2. The Slice Customers Group has failed to provide any reason why these utilities are now changing their position on the treatment of augmentation expenses or how its current position should be understood, in light of their previous statements to the contrary.

Additionally, the Partial Resolution of Issues was a negotiated agreement that had provisions that various parties endorsed, as well as others that they may not have specifically endorsed, but rather chose not to oppose. As such, the Partial Resolution of Issues was the result of a compromise by a variety of rate case parties. In addition to the support by public power, the IOUs, along with various tribal entities, also supported the adoption of the Partial Resolution of Issues by the Administrator. As a consequence, each of the provisions of the Partial Resolution of Issues was a package deal, where the various parts were interdependent upon all the others. The Slice Customers Group cannot now pick through the document and argue for a particular change, given the compromise that it represents.

The Partial Resolution of Issues was subsequently adopted by the Administrator in the WP-07 Administrator's Final Record of Decision, and BPA does not see any reason to undo that settlement and revisit this issue or any of the numerous issues addressed in that document. *See* Lefler, *et al.,* WP-07-E-BPA-63 at 6.

Q. The Slice Customers Group contends that BPA designated augmentation as not subject to true-up by merely by placing a dark black box around those costs and not identifying any substantive difference between these costs and those that are trued-up. Brawley and Gregg, WP-07-E-JP22-1. How do you respond?

A. We disagree with this characterization by the Slice Customers Group. BPA specifically identified a substantive reason for differentiating between those costs that are not subject to the Slice True-Up and those that are. Contrary to the conclusion by the Slice Customers Group, BPA did not merely designate those items not subject to Slice True-Up by placing a dark black box around those costs. As noted, the Partial Resolution of Issues specifically provided that the net cost of augmentation would not be trued-up to actual costs. The identification of those costs not subject to true-up by placing a dark black box around them was solely for ease of identification. Furthermore, BPA had already established in the WP-02 Final Proposal that by updating actual average megawatts of augmentation after the Subscription window closed and by having both Slice and non-Slice customers charged for the same forecast price for this amount of augmentation power assured equitable treatment between customer classes for this expense. *See* Administrator's Record of Decision, WP-02-A-02 at 16-29. Equitable treatment between customer classes was the substantive reason why BPA decided augmentation costs were not subject to the Slice True-Up.

Q. What updates to augmentation costs and revenue credits are you proposing for FY 2009?

A. We are proposing relevant updates to the FY 2009 Other Augmentation costs in this Supplemental Proposal. *See* Supplemental Wholesale Power Rate Development Study, WP-07-E-BPA-49 at 123. We increased the augmentation need to 354 aMW in FY 2009 and the purchase price to $61.42 per megawatthour. *Id.* We revised the related revenue credit, based on $26.15 per megawatthour for the PF Preference rate. *Id.*

Q. *In Section 3 of this testimony, entitled "Treatment of the Reduction of Risk Discount," you appear to be relaxing the standard of not subjecting the cost items in the "Augmentation Cost Box" to the Slice True-Up by allowing Slice customers to receive payments for the elimination of the IOU Reduction of Risk Discount expense. This seems inconsistent with the treatment of Other Augmentation Costs and related revenue credits, which you state are still not subject to the Slice True-Up. Please explain.*

A. We believe there is an important distinction between the two types of costs (IOU Reduction of Risk Discount expense and the Other Augmentation Cost and related revenue credits) in the "Augmentation Cost Box" in the Slice Product Costing and True-Up Table that warrants disparate treatment.

The distinction is that the IOU Reduction of Risk Discount is a cost that we determined to be affected by the Ninth Circuit rulings on challenges to BPA's REP Settlement Agreements, the LRAs, and the 2004 Amendments. *See* Bliven, *et al.*, WP-07-E-BPA-52. BPA determined that the IOU Reduction of Risk Discount payments to IOUs should be treated as improper payments. *Id.* at 20. Because of this treatment, we have no basis for assessing such amount to the Slice customers. Therefore, we propose to not "true up" these costs through the Slice True-Up, but rather credit Slice customers for the amount that was not assessed. As noted earlier, BPA will do this in conjunction with the 2008 True-Up process.

By contrast, Other Augmentation Expenses, along with all the other line items in the Slice Revenue Requirement, are legitimate costs that we have a basis to propose charging to all customers. Most assessed costs are subject to being trued up to actual expenses, but for the reasons previously discussed in this testimony, BPA and the customers agreed not to true up Other Augmentation Expenses.

Q. *If the IOU Reduction of Risk Discount expense is not subject to the Slice True-Up, how do you propose to credit the Slice customers for the amount that was not properly assessed?*

A. We propose to work within the construct of the Slice True-Up to credit the Slice customers for the amount of the IOU Reduction of Risk Discount expense that is not subject to the Slice True-Up. Specifically, we propose to calculate each Slice customer's share of the IOU Reduction of Risk Discount amount that was not assessed and multiply that amount by the Slice customer's Slice percentage. We propose this amount (Slice customer's Slice percentage share) will be included in each Slice customer's True-Up Adjustment Charge calculation as an Individual Credit.

Q. *Why do you have to credit Slice customers through the Slice True-Up for the amount of the IOU Reduction of Risk Discount expense that was not assessed?*

A. We propose to credit Slice customers through the Individual Credit mechanism in the Slice True-Up because the IOU Reduction of Risk Discount was not subject to the Slice True-Up. By using the Individual Credit mechanism, Slice customers can receive this credit. However, we will ensure that Slice customers do not get credited twice.

Q. *Won't Slice customers signing the Standstill Agreements already get credited through Standstill payments and related true-up for the amount of the IOU Reduction of Risk Discount expense that was not properly assessed?*

A. Yes, but the Slice True-Up could undo the Standstill payments and related true-up, because the IOU Reduction of Risk Discount expense is not subject to the Slice True-Up. We propose to ensure that Slice customers receive their proportionate share of the amount of the expense that was not properly assessed, and ensure that no double payments for this expense are made to Slice customers.

Section 5: The Lookback Study Treatment of the Slice Customer Payments

Q. *The Slice Customers Group describes the steps BPA proposed to take to allocate the FY 2007-2008 overcharge amounts. Brawley and Gregg, WP-07-E-JP22-1 at 7. There were four steps listed. Id. Do you agree that these steps are consistent with the Supplemental Proposal for the allocation of the FY 2007-2008 overcharge amounts?*

A. Yes. We agree that these steps are consistent with the Supplemental Proposal for the allocation of the FY 2007-2008 overcharge amounts.

Q. *The Slice Customers Group states that BPA is not proposing to correct the amounts in Tables 15.15.1, 15.15.2, and 15.15.3 (see Lookback Study Documentation, WP-07-E-BPA-44 at 214-216) to the individual Slice Participant's Slice percentage, but instead proposes to credit these amounts based on the basis of the FY 2007 revenues. Brawley and Gregg, WP-07-E-JP22-1 at 7. Do you agree?*

A. Yes. We did not propose to correct or modify the amounts in the Tables 15.15.1, 15.15.2, and 15.15.3 through the Slice True-Up for FY 2008. As we stated in Section 3 of this testimony, we propose that the Slice True-Up for FY 2008 will not alter the amounts of Standstill and true-up payments that are due to the Slice customer signing the Standstill Agreements, nor will it alter the Slice Customer Payment Amounts, plus interest, that are due to the Slice customers that do not sign the Standstill Agreements.

Q. *The Slice Customers Group states that because individual Slice customers have different billing factors that go in to their individual revenue calculation, using the FY 2007 revenues will result in a misallocation among Slice customers. Brawley and Gregg, WP-07-E-JP22-1 at 7-8. Do you agree?*

A. No. We do not agree that there will be a misallocation of the FY 2007-2008 overcharge amounts using the FY 2007 revenues if the allocation is based on individual revenue calculations for Slice customers. This is simply one method for allocation of the

FY 2007-2008 overcharge amounts – a method that the Slice customers negotiated for in the Standstill Agreements.

Q. The Slice Customers Group states that the revenue calculation BPA used to allocate the Customer Payment Amount includes credits for the Low Density Discount (LDD) of those (Slice) utilities. Brawley and Gregg, WP-07-E-JP22-1 at 8. The Slice Customers Group also state that the PNGC members' FY 2007 revenues differ from their Slice percentage due to the LDD credits (primarily). Id. Do you agree?

A. Yes. We agree that the revenue calculation BPA used to allocate the Customer Payment Amount includes credits for the Low Density Discount (LDD) of those utilities. We also agree that, for PNGC, an allocation of the FY 2007-2008 overcharges based on PNGC's FY 2007 revenue share of the total FY 2007 Slice revenues would result in a Customer Payment Amount to PNGC that was different than an allocation based on its Slice percentage.

Q. The Slice Customers Group proposes that when BPA reaches the last step in the process, the allocation of Customer Payment Amounts among Slice customers, it use the Selected Slice Percentage of each Slice customer to make such allocation. Brawley and Gregg, WP-07-E-JP22-1 at 8. The Slice Customers Group states further that this proposal will ensure that, among the Slice customers, such rate provisions as the LDD do not result in a misallocation among the Slice customers. Id. Do you agree?

A. We will consider using the Slice Percentage of each Slice customer to allocate the FY 2007-2008 overcharges, using the Slice True-Up process in the "last step of the process," as proposed by the Slice Customers Group.

Q. How would you implement the Slice Customers Group's suggestion to allocate the FY 2007-2008 overcharges using the Slice True-Up process in the last step of the process?

A. We would calculate each customer's Slice True-Up Adjustment as if there were no payments from Standstill Agreements. Each Slice customer would then have a credit reflected in each of their Slice True-Up Adjustment Charges. For those Slice customers who signed a Standstill Agreement, we would account for the net payment (net Standstill payment and related true-up amount) as an Individual Charge. This shows as an Individual Charge so that it is treated as if there was a prepayment for the return of FY 2007-2008 overcharges. In this manner, the Slice True-Up calculation and the Standstill Agreements would work together to ensure that there is no double payment for FY 2007-2008 overcharges, and to ensure that the end result is an allocation of the FY 2007-2008 overcharges in accordance with customers' Slice Percentages. Any interest received through the Standstill Agreements would be kept out of the accounting for the Slice True-Up calculation.

For customers that did not sign Standstill Agreements, we would calculate each customer's Slice True-Up Adjustment, and allow the True-Up process to allocate the FY 2007-2008 overcharges to the customers per their Slice Percentages. Any Definitive Payment Amount interest determined to be paid to customers who did not sign the Standstill Agreements would be kept out of the accounting for the Slice True-Up calculation.

Q. Does this conclude your testimony?

A. Yes.

DATA REQUEST NUMBER TO REFERENCE:
BPA-JP22-3

RESPONSE BY:
Steve Andersen - JP22

ORIGINAL DATA REQUEST:
The Slice Customers' Group testimony states, "We recommend that the Slice customers receive their shares (collectively, 22.6278 percent of the $46.048 million paid by PF customers in FY 2007-2008)in a lump sum payment as their respective shares of the Reduction of Risk Discount return."

When would this lump sum paid to Slice customers? Through their True-Up Adjustment Charge for FY 2008?

EXHIBIT: Direct Testimony of Slice Customers Group WP-07-E-JP22-1

PAGE(S): 5
LINE(S): 8-10

DATA RESPONSE:

--TEXT DESCRIPTION:
Response to BPA-JP22-3:

The lump sum payment correction associated with both FY-2007 and FY-2008 should be made as part of the FY-2008 Slice True-Up.

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B O N N E V I L L E   P O W E R   A D M I N I S T R A T I O N

2007 Supplemental Wholesale Power Rate Case Initial Proposal

REBUTTAL TESTIMONY

IMPLEMENTATION OF 7(B)(2) (FY 2002-2009)

May 2008

WP-07-E-BPA-85

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RONALD J. HOMENICK and MICHAEL J. MACE

Witnesses for Bonneville Power Administration

SUBJECT: IMPLEMENTATION OF 7(B)(2) (FY 2002-2009)

Section 1: Introduction and Purpose of Testimony

Q. Please state your names and qualifications.

A. My name is William J. Doubleday and my qualifications are contained in WP-07-Q-BPA-11.

A. My name is Raymond D. Bliven and my qualifications are contained in WP-07-Q-BPA-58.

A. My name is Paul A. Brodie and my qualifications are contained in WP-07-Q-BPA-07.

A. My name is Ronald J. Homenick and my qualifications are contained in WP-07-Q-BPA-17.

A. My name is Michael J. Mace and my qualifications are contained in WP-07-Q-BPA-33.

Q. Have you previously submitted testimony in this Supplemental Proceeding?

A. Yes. Mr. Doubleday, Mr. Bliven, Mr. Brodie, and Mr. Homenick have submitted direct testimony, with other witnesses, identified as Exhibits WP 07 E BPA 58 and WP 07 E BPA 70. Mr. Doubleday, Mr. Bliven, and Mr. Brodie have submitted direct testimony identified as Exhibit WP 07 E BPA 60. Mr. Doubleday, Mr. Bliven, Mr. Brodie, and Mr. Mace have submitted direct testimony identified as Exhibit WP 07 E BPA 68. Mr. Bliven and Mr. Brodie have submitted direct testimony, with other witnesses, identified as Exhibit WP

07 E BPA 62. Mr. Doubleday and Mr. Bliven (as a replacement for Mr. Keep) have submitted direct testimony, with other witnesses, identified as Exhibit WP 07 E BPA 69. Mr. Bliven has also submitted direct testimony, with other witnesses, identified as Exhibits WP 07 E BPA 52, WP 07 E BPA 53, WP 07 E BPA 57, and WP 07 E BPA 63. Mr. Homenick has also submitted direct testimony, with other witnesses, identified as Exhibits WP 07 E BPA 55, WP 07 E BPA 59, WP 07 E BPA 65, WP 07 E BPA 74, and WP 07 E BPA 75.

Q. Please state the purpose of your testimony.

A. The purpose of this testimony is to respond to the parties' direct testimonies regarding BPA's implementation of the section 7(b)(2) rate test.

Q. How is your testimony organized?

A. This testimony consists of seventeen sections. Section 1 explains the purpose and scope of the testimony. Section 2 discusses the Lookback Method. Section 3 discusses the treatment of certain loads and resources in the 7(b)(2) rate test. Section 4 discusses BPA's revenue requirement in the 7(b)(2) rate test. Section 5 discusses Mid-Columbia resources. Section 6 discusses the treatment of conservation resources. Section 7 discusses the verification and documentation of resources and their costs and the modeling of resource costs in the resource stack. Section 8 discusses estimated financing cost. Section 9 discusses conservation accounting treatments and financing conservation costs. Section 10 discusses obsolete conservation. Section 11 discusses reserves available to the 7(b)(2) Case. Section 12 discusses applicable 7(g) costs. Section 13 discusses the subject of uncontrollable events being applicable 7(g) costs in the 7(b)(2) Case. Section 14 discusses applicable 7(g) costs and DSI financial benefits. Section 15 discusses Slice surplus sales. Section 16 discusses rate test issues. Section 17 discusses DSI loads and rates in the 7(b)(2) rate test.

Section 2: Lookback Method

Q. *The IOUs argue that in applying the section 7(b)(2) rate test as of spring 2001, BPA should correct each of the flaws in BPA's performance of the section 7(b)(2) rate test identified elsewhere in their testimony. LaBolle, et al., WP-07-E-JP6-08 at 78. Please respond.*

A. Rather than make a blanket statement here, we will address each issue as it is presented. The resolution of each issue will be incorporated into the calculation of the rates, including the section 7(b)(2) rate test. However, some issues that were not raised in the respective rate proceedings may not be appropriate to incorporate in a backward looking application in this proceeding.

Q. *Cowlitz/Clark argue that BPA calculates a level of benefits in the range of $190 million dollars in each of the years FY 2002-2009 by changing the cost and load assumptions for use in the 7(b)(2) Case in a number of ways not listed in section 7(b)(2) of the Northwest Power Act and it is the differences from these changes that results in high REP benefit levels. Schoenbeck and Beck, WP-07-E-JP17-01 at 14. Cowlitz/Clark then argues that these changes result in an inappropriately high net exchange benefit. Id. at 15. Do you agree?*

A. BPA will address properly raised legal issues regarding whether BPA's cost and load assumptions are consistent with section 7(b)(2) in the Draft and Final Records of Decision in this proceeding. However, we appropriately changed cost and load data to reflect "time-of-reference" differences related to the recalculation of the PF Exchange rate for the FY 2002-2006 time period. Changes to data and methodology were also made to reflect the removal of BPA's REP Settlement Agreements with regional IOUs and the more robust litigation of section 7(b)(2) rate test issues that would have ensued. We believe these changes are reasonable and we will address the individual merits of each issue when raised.

Cowlitz/Clark's *ad hominem* statement in testimony that BPA's rate proposal is oriented toward a result similar to the REP Settlement Agreements is simply false. Contrary to Cowlitz/Clark's suggestion, some of our proposed changes tend to increase REP benefits and some of the changes tend to decrease REP benefits. For example, the removal of the portion of Mid-Columbia resources that are dedicated to serving IOU regional loads from the 7(b)(2)(D) resource stack, all else being equal, will increase REP benefits; but the removal of obsolete conservation from the resource stack, all else being equal, would decrease REP benefits.

Q. Cowlitz/Clark argue that they made a series of modifications in BPA's FY 2002-2006 RAM essentially eliminating the differences created by the assumptions listed in section 7(b)(2). Schoenbeck and Beck, WP-07-E-JP17-01 at 14. The test assumed: (1) BPA did not serve any DSI load in the Program Case, so no DSI load would be transferred into the preference customers' general requirements in the 7(b)(2) Case; (2) the FBS was adequate to serve the preference customers' general requirements in the Program Case so the same preference customers' general requirements would be served by the same FBS resources in both Cases; and (3) there was no reserve benefit and no material financing benefit difference between the two Cases. Id. Cowlitz/Clark argue that under these conditions, none of the section 7(b)(2) assumptions should cause any difference between the Program Case and the 7(b)(2) Case because the effect of each section 7(b)(2) assumption would be zero under the assumptions Cowlitz/Clark used for this preliminary check of BPA's RAM. Id. Yet, when Cowlitz/Clark ran BPA's FY 2002-2006 RAM with these assumptions, the RAM still produced significant REP benefits to be paid for entirely by preference customers. Id. Is this result necessarily inappropriate?

A. No. Although Cowlitz/Clark made a series of modifications in BPA's FY 2002-2006 RAM that they argue essentially eliminated the differences created by the assumptions listed in 7(b)(2), this is not the case. Simply assuming no DSI load, an FBS large enough to serve preference customer load in the Program Case, and no reserve or financing benefits, does not cover all of the differences between the Program and 7(b)(2) Cases. The amount of surplus sales contracts served in each Case is different because the 7(b)(2) Case serves only pre-Act contracts first. Because the FPS contract sales served first are different, the amount of FBS resource available to serve PF load is different in each Case. The Program Case has the cost and power amounts associated with "New Resources," while the 7(b)(2) Case does not. The 7(b)(2) Case PF loads are higher to reflect the fact that conservation programs in the Program Case have not occurred in the 7(b)(2) Case.

In addition, if there were a situation where the only difference between the Program and 7(b)(2) Cases was the cost of the REP, the 7(b)(2) rate test trigger may or may not be large enough to force the REP benefits to zero. The 7(b)(2) rate test trigger is the result of discounting, averaging, and rounding two streams of rates, one from the Program Case and the other from the 7(b)(2) Case. Therefore, the actual trigger calculated may not be perfectly associated with the monetary differences between the Program and 7(b)(2) Cases, that is, the rate protection amount calculated as the 7(b)(2) rate test trigger times the PF Preference load may not be equal to the simple average of the annual revenue requirement differences between the Program and 7(b)(2) Cases.

Q. Cowlitz/Clark argue that BPA's modeling of the 7(b)(2) Case includes an inappropriate adjustment to the preference customers' general requirements from what was used in the Program Case. Schoenbeck and Beck, WP-07-E-JP17-01 at

15. BPA increases the 7(b)(2) Case general requirements to eliminate the effect of historical conservation programs. Id. BPA states that this adjustment is necessary in order to include conservation in the 7(b)(2) Case resource stack. Id. The increase in preference customers' general requirements in the 7(b)(2) Case is between 500 and 750 aMW over the Program Case due to this "conservation" adjustment. Id. Do you agree?

A. No. As discussed further below, when beginning the section 7(b)(2) rate test, we use the same general requirements in the 7(b)(2) Case as used in the Program Case. Then we properly increased the 7(b)(2) Case PF loads to reflect the fact that we are instructed by the Implementation Methodology to include programmatic conservation in the 7(b)(2)(D) resource stack and use resources from the stack to serve 7(b)(2) Customer load after the FBS is exhausted.

Q. Cowlitz/Clark note that they have not run sensitivities correcting the modeling changes with which they disagree, but have performed more limited sensitivities verifying their understanding of how section 7(b)(2) should work with the errors described above corrected. Schoenbeck and Beck, WP-07-E-JP17-01 at 27. In particular, with regard to the FY 2007-2008 and FY 2009 RAMs, it was readily possible to eliminate the revenue requirement inconsistencies with regard to FBS costs, maintain the same preference load between the Program Case and the 7(b)(2) Case, and eliminate all conservation resources from the 7(b)(2) Case resource stack using the models BPA provided in February. Id. These FY 2007-2008 and FY 2009 RAMs are quite similar and more transparent to a user then the FY 2002-2006 RAM. Id. As they would expect, when the inputs are corrected for the errors they describe, the section 7(b)(2) rate protection is much greater and the REP benefits are eliminated. Id. Please respond.

A. As discussed previously, we do not agree with many of the changes to the section 7(b)(2) rate test that are proposed by Cowlitz/Clark. However, we do agree that erroneous changes made with the purpose of driving the REP benefits to zero can be input into the models and, in that circumstance, the model results may well be zero REP benefits.

Q. Cowlitz/Clark argue that performing similar sensitivities with the FY 2002-2006 RAM is much more problematic. Schoenbeck and Beck, WP-07-E-JP17-01 at 27. Please respond.

A. The FY 2002-2006 RAM is the rate model used in the WP-02 Final Proposal, it is the only rate model that was available in the winter/spring of 2001, and therefore, it is the appropriate model to use for the FY 2002-06 Lookback analysis. Subsequent to the WP-02 rate proceeding, BPA developed another RAM model that is more transparent and user friendly. However, when we were required to revisit the WP-02 rate period, it was necessary to disinter the FY 2002-2006 RAM. We have provided the FY 2002-2006 RAM to the parties to help demonstrate how the Supplemental Proposal calculated the values published in the Supplemental Proposal documentation and used in the Lookback analysis.

Q. Cowlitz/Clark argue that they have no confidence that the model can be used to correctly perform the section 7(b)(2) rate test. Schoenbeck and Beck, WP-07-E-JP17-01 at 28. They argue BPA should populate the FY 2009 RAM with the FY 2002-2006 input data and provide it to all parties. Id. Please respond.

A. As stated above, the rate model available in the winter/spring of 2001 was the FY 2002-2006 RAM. Although the FY 2009 RAM is easier to manipulate to produce rate scenarios, it was not available in the timeframe of the WP-02 rate proceeding. We provided the FY 2002-2006 RAM to the parties to help demonstrate how it arrived at its Initial Proposal values published in the Supplemental Proposal documentation. Furthermore, entering the FY 2002-2006 data into the FY 2009 RAM is a tremendous undertaking that would take an inordinate amount of time. Given the amount of data that would have to be transferred and verified, the process would take weeks. Furthermore, the results of the FY 2002-2006 RAM were previously tested through the WP-02 section 7(i) rate proceeding. The FY 2002-2006 RAM was the model that was used to produce the WP-02 rates; the FY 2009 RAM was not. We understand Cowlitz/Clark's concerns about the FY 2002-2006 RAM. Gaining the ability to perform rate analysis scenarios was one of the prime motivators that led us to produce the FY 2007-2008 RAM, which is the core of the FY 2009 RAM. However, we do not believe that Cowlitz/Clark's proposed solution to the difficulty in running 2002-06 rate scenarios is workable in the timeframe at hand. Finally, we are confident that the FY 2002-06 RAM models our rate proposal properly.

Section 3: Treatment of Certain Loads and Resources

Q. APAC notes that the definition of DSI Loads in the proposed Implementation Methodology provides that DSI loads "are forecast to be served by BPA, during the Five-Year Period, pursuant to sections 5(d)(1) or 5(f) of the Northwest Power Act." Wolverton, WP-07-E-AP-1 at 60-61. APAC argues that section 5(f) loads should not be included in the rate test calculations, assuming such loads are "within or adjacent," because sections 5(d)(1) and 7(c) of the Northwest Power Act place requirements and constraints on DSI sales that are part of the benefits calculation in the 7(b)(2) rate test, which do not apply to section 5(f) sales. Id. Do you agree?

A. The proposed Implementation Methodology provides that DSI loads are to be added to the 7(b)(2) Customer load in the 7(b)(2) Case. The proposed Implementation Methodology does not distinguish DSIs by whether they have section 5(d) or section 5(f) contracts. This is in conformance with the proposed Legal Interpretation. BPA will address parties' properly raised legal issues regarding the correctness of BPA's Legal Interpretation in the Draft and Final Records of Decision in this proceeding.

Q. APAC argues that BPA's section 5(f) proposal for DSI loads also would prevent the resources that serve those loads from entering the rate stack and being available to meet 7(b)(2) Customer load, whether those resources come from the FBS or "the stacking provisions of section 7(d) [sic]." Wolverton, WP-07-E-AP-1 at 62. Do you agree?

A. No. APAC is wrong that the type of resources that are used to serve DSI load, or any other load, has any bearing on whether the resource is included in the resource stack. The proposed Implementation Methodology instructs which resources should be included in the 7(b)(2)(D) resource stack. The proposed Implementation Methodology is in conformance with the proposed Legal Interpretation. BPA will address parties' properly raised legal issues regarding the correctness of BPA's Legal Interpretation in the Draft and Final Records of Decision in this proceeding.

Whether the resources serving 5(f) loads are available in the 7(b)(2) Case depends on which resource pool is determined to serve the 5(f) load. If the 5(f) load is served by the New Resources resource pool, the resources will be included in the section 7(b)(2)(D) resource stack, in accordance with the Implementation Methodology. This treatment of placing New Resources in the section 7(b)(2)(D) resource stack is without distinction to what loads these resources are serving, whether 5(d)(1) loads or 5(f) loads. Conversely, FBS resources cannot be placed in the resource stack, whether they are serving 5(b) load, 5(d)(1) load or 5(f) load. It is the resource pool into which each resource is placed that determines whether or not it is included in the resource stack.

Q. *Cowlitz/Clark argue that the Northwest Power Act allows BPA to serve non-preference customer loads in the 7(b)(2) Case with FBS under two conditions. Schoenbeck and Beck, WP-07-E-JP17-01 at 25-26. The first condition has to do with the "within or adjacent" DSI load. Id. The second condition has to do with existing obligations as of the effective date of the Northwest Power Act. Id. Do you agree?*

A. BPA will respond to parties' properly raised legal arguments in the Draft and Final Records of Decision in this proceeding. Nevertheless, we agree that Cowlitz/Clark have correctly stated the two general instances when FBS resources are used to serve loads other than those of public bodies, cooperatives, and Federal agencies. In addition, however, there may be circumstances where serving pubic body customer load with FBS resources in the 7(b)(2) Case is proper even if those sales were not actually made under the PF Preference rate.

Q. *Cowlitz/Clark note that BPA has contractual obligations today that pre-date the Northwest Power Act, including contractual obligations associated with Canadian Entitlement return, Bureau pumping load and Hungry Horse reservation loads. Schoenbeck and Beck, WP-07-E-JP17-01 at 26. Cowlitz/Clark argue that BPA can serve any post-Northwest Power Act contractual obligations with the FBS in the 7(b)(2) Case only after first satisfying the pre-Northwest Power Act obligations and the 7(b)(2) Customer load (which does not include new large single loads) served under section 5(b) of the Act, that is, the general requirements of preference customers. Id. Do you agree?*

A. BPA will respond to parties' properly raised legal arguments in the Draft and Final Records of Decision in this proceeding. Nevertheless, we agree that Cowlitz/Clark have correctly stated the pre-Northwest Power Act obligations and that 7(b)(2) Customer load does not include new large single loads. In addition, as stated above, there may be circumstances where serving pubic body customer load with FBS resources in the 7(b)(2) Case is proper even if those sales were not actually made under the PF Preference rate. Furthermore, if the FBS in a particular year is large enough to serve some post-Act FPS sales as well as the PF Preference rate load, those post-Act FPS sales may be served with this surplus FBS.

Q. Cowlitz/Clark argue that BPA has reduced the FBS available to meet general requirements of preference customers in the 7(b)(2) Case in order to meet contract obligations incurred after adoption of the Northwest Power Act. Schoenbeck and Beck, WP-07-E-JP17-01 at 26. In the FY 2002-2006 RAM, BPA has inappropriately reduced the FBS available to serve general requirements in the 7(b)(2) Case by the amount of pre-Subscription contracts. Id. Prior to determining the FBS available to serve the 7(b)(2) Case general requirements, BPA first deducts the pre-Northwest Power Act contractual load, the Hungry Horse obligation and the pre-Subscription contracts. Id. These below-cost pre-Subscription contracts average about 700 aMW. Id. As these contracts were made after the effective date of the Northwest Power Act and they were entered into as surplus sales under sections 5(f) and 7(f) and not under sections 5(b) and 7(b), these obligations cannot be assumed to reduce the FBS resources available to serve general requirements load in the 7(b)(2) Case. Id. Do you agree?

A. No. The pre-Subscription sales were sales of firm power BPA primarily made to a subset of BPA's public body customers. The pre-Subscription sales were not made under section 5(b) of the Northwest Power Act like most firm sales to BPA's public body customers, but rather under section 5(f) to give these public body customers price certainty (based on the PF-96 Preference rate) for the first five years of the Subscription contract period. However, the pre-Subscription customers were historically (and continue to be) public body customers whose power requirements were (and are) generally met with section 5(b) sales. These customers received PF Preference-priced power under section 5(b) contracts prior to the FY 2002-2008 time period; some of these customers received additional sales of power for this time period under section 5(b); and the majority of the pre-Subscription contracts were converted into general requirements contracts, that is, section 5(b) sales, for the FY 2007-2011 time period. Therefore, BPA believes these pre-Subscription sales should be reflected in the 7(b)(2) Case. BPA could have defined the sales, for purposes of the 7(b)(2) Case, as PF load. However, because these sales were made under section 5(f) and had specific contractual rates attached, BPA chose to serve them before the actual PF load. The load/resource balance would be the same under either treatment of service, and the same amount of resources would be taken from the resource stack in either Case.

In addition, if the FBS in a particular year is large enough to serve some post-Act FPS sales as well as the PF Preference rate load, those post-Act FPS sales may be served with this surplus FBS. This is the case for the pre-Subscription sales for the years FY 2002-2006. *See* FY 2002-2008 Lookback Study Documentation, WP-07-E-BPA-44A at 196, Column G. The pre-Subscription sales for FY 2007-2010 are associated with BPA's Hungry Horse obligation and are correctly included in the 7(b)(2) Case.

Q. *Cowlitz/Clark note that BPA did not treat the pre-Subscription obligations as if they were section 7(b) sales in the Program Case and that BPA correctly modeled the obligations as surplus sales. Schoenbeck and Beck, WP-07-E-JP17-01 at 26-27. It is only in its 7(b)(2) Case modeling that BPA has re-characterized these commitments as having a claim to the FBS superior to that of the general requirements of preference customers. Id. These obligations, which are in place during the FY 2002-2006 period, should be removed from the 7(b)(2) Case in determining the available FBS. Id. Do you agree?*

A. No. The pre-Subscription sales were sales of firm power BPA made primarily to a subset of BPA's public body customers. In order to make a comparison of the costs of power to public body customers in the Program and 7(b)(2) Cases, the total loads of the public body customers should be reflected in both Cases.

As stated above, if the FBS in a particular year is large enough to serve some post-Act FPS sales as well as the PF Preference rate load, those post-Act FPS sales may be served with this surplus FBS. This is the case for the pre-Subscription sales for the years FY 2002-2006. *See* FY 2002-2008 Lookback Study Documentation, WP-07-E-BPA-44A at 196, Column G. The pre-Subscription sales for FY 2007-2010 are associated with BPA's Hungry Horse obligation and are correctly included in the 7(b)(2) Case.

Q. *WPAG argues that BPA has improperly reduced the FBS capability available to serve loads in the 7(b)(2) Case for obligations other than those existing as of December 5, 1980. Grinberg, et al., WP-07-E-WA-05 at 19. In the recalculation of the 7(b)(2) rate test for the WP-02 rate period, BPA has reduced the FBS available for the 7(b)(2) Case by about 720 aMW to reflect service to pre-Subscription contracts signed with certain preference customers under 5(f) of the Northwest Power Act. Id. The contracts between BPA and the pre-Subscription* *purchasers were not in existence in December of 1980. Id. As a consequence, WPAG argues they are not a permitted reduction to the FBS capability available for the 7(b)(2) Case. Id. Do you agree?*

A. First, it should be clarified that BPA has not changed the capability of the FBS resources in the 7(b)(2) Case. Such resource capability remains constant. The issue involves using the FBS to meet public agency customer loads in the 7(b)(2) Case, and whether BPA should use FBS resources to meet public agency customer loads when such loads have been section 5(b) requirements loads and are receiving guaranteed service at a rate based on the PF Preference rate that provided them substantial pricing benefits.

As noted previously, the pre-Subscription sales were sales of firm power BPA made primarily to a subset of BPA's public agency requirements customers. The pre-Subscription sales were made under section 5(f) of the Northwest Power Act due to the particular circumstances existing at the time the sales were made. At that time, BPA faced uncertainty in retaining public agency loads when market prices were low. BPA had experienced both public agency and direct service industrial load loss in the years just prior to the execution of these contracts. BPA sought to obtain early load commitments and wanted to sell these customers section 5(b) requirements power at the PF Preference rate. The customers, however, wanted rate certainty that was not available through the PF Preference rate. Although these sales would otherwise have been section 5(b) sales at the PF Preference rate, BPA agreed to accommodate the desires of these section 5(b) requirements customers by using a price structure (including, for example, price collars) available under BPA's FPS rate, which was developed under section 7(f) of the Northwest Power Act. Because of this pricing structure, loads under these contracts were served at a rate that allowed a minimal number of price adjustments and could not be allocated additional costs under section 7(b)(3) of the Northwest Power Act, thereby receiving substantial cost protection.

In any event, as noted previously, if the FBS in a particular year is large enough to serve some post-Act FPS sales as well as the PF Preference rate load, those post-Act FPS sales may be served with this surplus FBS. This is the case for the pre-Subscription sales for the years FY 2002-2006. *See* FY 2002-2008 Lookback Study Documentation, WP-07-E-BPA-44A at 196, Column G. The pre-Subscription sales for FY 2007-2010 are associated with BPA's Hungry Horse obligation and are correctly included in the 7(b)(2) Case.

Q. *WPAG argues that BPA should reverse these adjustments and increase the size of the FBS capability available in the 7(b)(2) Case for both WP-02 and WP-07 by the amount of the transactions between BPA and the pre-Subscription purchasers. Grinberg, et al., WP-07-E-WA-05 at 20. Do you agree?*

A. No. Section 7(b)(2) of the Northwest Power Act is constructed around assumptions based on serving the general requirements of BPA's public body, cooperative, and Federal agency (collectively, "public agency") customers. The costs of the 7(b)(2) Case are determined by assessing the resources used to meet the public agencies' general requirements loads. If such loads are smaller, fewer resources are needed to serve such loads, and the cost of the 7(b)(2) Case is lower. Conversely, if the loads are larger, more resources are needed to serve such loads, and the cost of the 7(b)(2) Case is higher. Public agencies want the cost of the 7(b)(2) Case to be lower in order that, when compared to the generally higher Program Case, there will be a larger difference resulting in a "trigger" and the consequent allocation of costs away from public agency rates to non-public agency rates. Therefore, the public agencies do not want BPA to treat the pre-Subscription loads as equivalent to section 5(b) requirements loads.

Looking at these circumstances objectively, the loads in the 7(b)(2) Case normally include the section 5(b) requirements loads of the pre-Subscription customers. Thus, such loads for many years have been included as requirements loads in the 7(b)(2) Case. The question then becomes whether, in special circumstances where BPA has accommodated its public agency customers by allowing them to purchase firm power from BPA in the amount of their section 5(b) requirements at special limited prices based on the PF Preference rate (which is used for section 5(b) requirements sales), the public agency customers should *also* receive a windfall through the operation of section 7(b)(2) by excluding the pre-Subscription loads from the loads to be served in the 7(b)(2) Case. WPAG's suggestion to do so would improperly place form over substance, thereby providing windfall benefits to public agencies at the expense of BPA's other customers. Such an unfair, unintended result should not occur.

Furthermore, as noted previously, if the FBS in a particular year is large enough to serve some post-Act FPS sales as well as the PF Preference rate load, those post-Act FPS sales may be served with this surplus FBS. This is the case for the pre-Subscription sales for the years FY 2002-2006. *See* FY 2002-2008 Lookback Study Documentation, WP-07-E-BPA-44A at 196, Column G. The pre-Subscription sales for FY 2007-2010 are associated with BPA's Hungry Horse obligation and are correctly included in the 7(b)(2) Case.

Section 4: Revenue Requirement

Q. Cowlitz/Clark state that BPA has a different hydro revenue requirement between the Program Case and the 7(b)(2) Case. Schoenbeck and Beck, WP-07-E-JP17-01 at 22. Is that correct?

A. Yes. One is derived (allocated) from the total Program Case revenue requirement and the other is derived from the total revenue requirement that is developed specifically for the 7(b)(2) Case, based on the relevant assumptions that guide the two respective Cases.

Q. Cowlitz/Clark state that BPA does two separate repayment studies to determine the interest and amortization revenue requirement for the Federal facilities, the real one on which it bases its rates and a separate one for the 7(b)(2) Case. Schoenbeck and Beck, WP-07-E-JP17 at 22. Is that correct?

A. Yes. The revenue requirement for each Case incorporates the results from a repayment study that is run using data that are consistent with the assumptions of the two respective Cases.

Q. Cowlitz/Clark contend that a repayment study essentially determines what level of interest and amortization payments are required to pay off BPA's debt obligations over a 50-year term. Schoenbeck and Beck, WP-07-E-JP17-01 at 22. For the Program Case, the repayment study includes the debt from acquisitions of both FBS and non-FBS resources, while the BPA 7(b)(2) Case includes only FBS debt. Id. In other words, BPA assumes in the 7(b)(2) Case that its obligation to repay the cost of non-FBS obligations simply disappears. Id. Since the pinch year in both studies is still controlled by the same ENW obligations, there is "more room" for pre-paying FBS obligations in the 7(b)(2) Case. Id. The direct result is then a much higher interest and amortization requirement in the 7(b)(2) Case for the FBS than in the Program Case. Id. Do you agree?

A. In general, Cowlitz/Clark have correctly characterized the operation of the repayment study. However, based on the data they present, they appear to confuse the results of the repayment study with the allocation of the components to the resource pools, specifically the FBS. Although they have focused primarily on the net interest and net revenues from the total revenue requirement that have been allocated to Hydro, the more appropriate comparison, given the operation of the section 7(b)(2) rate test, would between the full FBS in the two Cases. BPA's Fish & Wildlife program is also part of the FBS and receives allocations of net interest and net revenues. However, more importantly, the comparisons of capital-related costs are quite different between repayment studies and the revenue requirements allocated to the FBS.

Q. Cowlitz/Clark present a table showing the effect this second repayment study has had on the 7(b)(2) Case FBS requirement for each RAM model. Schoenbeck and Beck, WP-07-E-JP17-01 at 22. Cowlitz/Clark argue that the increase in revenue requirement for all three RAMs is over $1.1 billion, which is created by assuming that BPA has accelerated payments related to FBS resources in the 7(b)(2) Case over the payment schedule for those same resources in the Program Case. Id. Please elaborate on the different comparisons necessary to see the cost development between the Program and 7(b)(2) Cases.

A. Using the data for the 2009 portion of the rate tests (FY 2009-2013) as an example, Cowlitz/Clark first show a total difference of net interest between the two Cases of negative $2,650 (all $ in thousands herein) when the Program Case data are subtracted from the 7(b)(2) Case data for the costs allocated to Hydro. Directly from the repayment study, however, the gross interest between the Cases is negative $128,404. (*See* Attachment 1 for source data used here.) The amortization scheduled by the studies differs by positive $10,185, for a total difference between the Program Case and 7(b)(2) Case repayment study results of negative $118,219. Compare that figure to the total difference cited by Cowlitz/Clark of positive $215,832. This is quite disparate data and Cowlitz/Clark's conclusions cannot, then, be attributed solely to repayment study results. Although the repayment study did respond in its operation essentially as stated by Cowlitz/Clark, one of the most noteworthy differences between the two Cases is from revenue requirement development. Because BPA's conservation investments are not present at the outset in the 7(b)(2) Case, the revenue requirement for that Case excludes $279,657 of conservation amortization (non-cash annual write-down of the investment) that is in the Program Case revenue requirement. The Planned Net Revenues difference of positive $218,482 Cowlitz/Clark cites is directly affected by the exclusion of the conservation amortization because Planned Net Revenues, specifically the Minimum Required Net Revenues component, is calculated as the positive difference of scheduled Federal principal repayment and irrigation assistance payments less the non-cash expenses in the revenue requirement. Consequently, it is not really the repayment study that creates such a difference between the allocated costs in the two Cases, but it is a consequence of the different assumptions in the revenue requirements of each Case pertaining to the annual costs associated with conservation investments.

Q. Cowlitz/Clark argue that section 7(b)(2) does not specify that a separate repayment study should be done. Schoenbeck and Beck, WP-07-E-JP17-01 at 23. Do you agree?

A. BPA will respond to parties' properly raised legal argument in the Draft and Final Records of Decision in this proceeding. Nevertheless, while the lay reader may not find a reference to such a requirement in the Act, BPA has performed every 7(b)(2) rate test since conception (July 1, 1985) based on revenue requirements for the 7(b)(2) Case that incorporate the results of a repayment study that, as stated above, is consistent with the assumptions relevant to that Case.

Q. Cowlitz/Clark argue that BPA performs the second repayment study because BPA assumes the non-FBS resources it has acquired simply do not exist in the 7(b)(2)

Case, or at least that the obligation to pay for them does not exist. Schoenbeck and Beck, WP-07-E-JP17-01 at 23. Do you agree?

A. To a certain extent, yes. The guiding assumption for the 7(b)(2) Case repayment study is to exclude, specifically for the purpose of developing a 7(b)(2) Case revenue requirement, those costs associated with the Northwest Power Act that are required to be treated differently in the 7(b)(2) Case. The repayment study specifically includes Treasury bonds that fund BPA conservation capital programs, non-Federal debt service for conservation capital funding done by customers and backed by BPA, and the non-Federal debt service associated with non-FBS resources acquired under the authority of the Act. These particular costs are not present ("do not exist") in the initial stage when revenue requirements are developed for the 7(b)(2) Case.

Q. Cowlitz/Clark argue that nothing in section 7(b)(2) requires BPA to assume its obligation to pay for non-FBS resources has been altered. Schoenbeck and Beck, WP-07-E-JP17-01 at 23. They argue section 7(b)(2) addresses which of BPA's actual power resource costs should be allocated to the general requirements of the preference customers as opposed to cost to be allocated to other sales. Id. The fact that certain costs are not allocated to general requirements in the 7(b)(2) Case does not mean those costs do not exist. Id. It means only that the costs are to be allocated to other sales, including FPS sales. Id. Do you agree?

A. BPA will respond to parties' properly raised legal argument in the Draft and Final Records of Decision in this proceeding. In addition, however, it is not that "those costs do not exist". The associated resources are simply not part of what is assumed to be included in the available FBS resources at the outset of the rate test, and therefore the associated costs are not present in the 7(b)(2) revenue requirement. Rather, these other resources, and their associated costs, are placed into the 7(b)(2)(D) resource stack. If the FBS is insufficient to serve all the 7(b)(2) Case loads, resources are brought on from the 7(b)(2)(D) resource stack and their costs are then added to the 7(b)(2) Case revenue requirement. Given the different load/resource balances in the Program Case and 7(b)(2) Case, resources from the 7(b)(2)(D) resource stack may be brought on in different amounts than the specific resources in the Program Case.

Q. Cowlitz/Clark argue that the effect of BPA's assumption that the non-FBS resource obligations disappear from the repayment study in the 7(b)(2) Case is that it causes the 7(b)(2) Case preference load to pay a penalty – in the form of greater hydro interest and amortization expense – due to acquiring fewer resources in the 7(b)(2) Case. Schoenbeck and Beck, WP-07-E-JP17 at 23. In fact, Cowlitz/Clark argue, the FBS revenue requirement is what it is. Id. Both the Program Case and the 7(b)(2) Case should use the same hydro resource revenue requirement as determined from the Program Case repayment study. Id. Do you agree?

A. It may be a reasonable assumption to fix the FBS revenue requirement to be the same in both Cases, that is, "the FBS revenue requirement is what it is." If there were only one view of the FBS, once the FBS revenue requirement was determined in the Program Case, it might not be necessary to start over and establish another revenue requirement for the 7(b)(2) Case. However, throughout the history of the rate test BPA has approached the cost development as a "bottoms up" approach in which repayment requirements and resulting revenue requirements are determined by starting over from the Program Case and independently developing revenue requirements that only include those costs that are known at the outset of the analysis to be present in the 7(b)(2) Case. Only when resources are brought on from the 7(b)(2)(D) resource stack are the associated costs brought on in proportion to the amount of the resource needed, which may be entirely different than what is projected in the Program Case.

Section 5: Mid-Columbia Resources

Q. *APAC argues that section 7(b)(2)(D) does not exclude all resources committed to load but only those resources committed under section 5(b). Wolverton, WP-07-E-AP-1 at 71. Do you agree?*

A. The proposed Implementation Methodology instructs us to exclude all resources committed to load pursuant to section 5(b) from the 7(b)(2)(D) resource stack. This exclusion is in conformance with the proposed Legal Interpretation. BPA will address parties' properly raised issues regarding the correctness of BPA's Legal Interpretation in the Draft and Final Records of Decision in this proceeding.

Q. *APAC and WPAG argue that not all of the Mid-Columbia resources are committed to load under section 5(b) of the Northwest Power Act. Wolverton, WP-07-E-AP-1 at 77; Grinberg, et al., WP-07-E-WA-05 at 24. Do you agree?*

A. We agree that not all of the Mid-Columbia resources sold by 7(b)(2) Customers to non-preference entities have been dedicated to load under section 5(b) of the Northwest Power Act. However, numerous contracts exist where BPA's utility customers have dedicated their Mid-Columbia purchases to load. First, when BPA conducted the WP-02 supplemental rate case in 2000-2001, the IOUs had executed REP Settlement Agreements. Attached to the REP Settlement Agreements were separate firm power requirements contracts offered under section 5(b) of the Northwest Power Act. These contracts were intended to be "stand alone" contracts. Under those contracts, all IOUs that purchased Mid-Columbia resources from 7(b)(2) Customers dedicated such purchases to their own loads for purposes of calculating their net requirements. These requirements contracts have never been terminated by the parties. BPA will address parties' properly raised issues regarding the legal validity of such contracts in the Draft and Final Records of Decision.

Furthermore, for purposes of FY 2002-2008, if one assumes that the REP Settlement Agreements had not been offered and implemented, IOUs expecting to receive positive benefits under the REP would have executed Residential Purchase and Sale Agreements to implement the REP, just as they did in 1981. It would be absurd to think that IOUs eligible to receive benefits under the REP would fail to execute the RPSA and receive such benefits for their residential consumers. Similarly, in 1981 BPA offered requirements power sales contracts to its preference and IOU customers. All of the IOUs executed the 20-year requirements contracts. In each of the requirements contracts of IOUs that purchased Mid-Columbia resources from 7(b)(2) Customers, the IOUs dedicated such purchases to their own loads pursuant to section 5(b) of the Northwest Power Act. In the absence of requirements contracts, the IOUs could not purchase requirements power from BPA. The IOUs' 20-year requirements contracts expired in 2001.

In developing the Subscription contracts that followed the IOUs' 1981 RPSAs and requirements contracts, BPA offered the IOUs two options. One option was to execute an REP Settlement Agreement to resolve disputes arising under the REP. As noted above, the REP Settlement Agreements attached separate requirements power contracts with the IOUs. The Record of Decision for the REP Settlement Agreements provided that the IOUs could not purchase any requirements power other than the requirements power provided under the attached requirements contracts. The second option offered to the IOUs was to execute an RPSA to participate in the REP for the next 10-year period. Because the RPSA does not provide requirements power to the IOUs, the IOUs would have had to execute separate requirements contracts for their requirement power purchases from BPA. In 2000, the IOUs elected to execute the REP Settlement Agreements.

As noted previously, in the absence of the REP settlements, the IOUs would have executed RPSAs and participated in the REP. In addition to the RPSAs, the IOUs would have executed requirements power sales contracts with BPA for the 10-year Subscription period. Just as it would be absurd to think that IOUs eligible to receive benefits under the REP would fail to execute RPSAs in the absence of the REP settlements, it would be equally absurd to think that the IOUs would have failed to sign new requirements contracts for the 10-year Subscription period. The IOUs would not have given up the opportunity to purchase requirements power from BPA regardless of how frequently the IOUs might purchase such power. Thus, for purposes of FY 2002-2008, it is reasonable to assume the IOUs would have executed requirements contracts and dedicated their Mid-Columbia purchases to their own load in such contracts, just as they did in their 1981 requirements power sales contracts.

Furthermore, even assuming for the sake of argument that the IOUs would not have wanted to dedicate their Mid-Columbia resources to their loads under their requirements contracts, they would have had no choice but to do so. BPA's Section 5(b)/9(c) Policy states that as long as a utility acquired a resource prior to enactment of the Northwest Power Act and used it to meet its native load, the utility must continue to dedicate that resource to native load and cannot place a larger requirement on BPA. Furthermore, even if a power sales contract expired after enactment of the Northwest Power Act, if there were a follow-on contract for the same resource, this would not be treated as a loss of contract right. Instead, the follow-on purchase would also have to be dedicated to the utility's native load.

Finally, BPA is currently negotiating requirements power sales contracts with the IOUs for both the period from October 1, 2008, through September 30, 2011 ("bridge contract"), and for the period from October 1, 2011, through September 30, 2028 ("Regional Dialogue contract"). *See* Attachments 2 and 3. Such contracts are scheduled to be executed in August 2008. Just as the IOUs dedicated their Mid-Columbia resources to native load in their 1981 requirements contracts and their 2000 requirements contracts, the IOUs will continue to do so as described in this testimony in the bridge and Regional Dialogue requirements contracts.

Q. APAC argues that the contracts provided in response to its data request for contracts with Northwest IOUs under Northwest Power Act section 5(b) in force during 2002-2008 were the section 5(b) requirements contracts BPA executed as a part of REP Settlement Agreements. Wolverton, WP-07-E-AP-1 at 72. APAC argues that these agreements are no longer enforceable and cannot be considered to commit resources to load. Do you agree?

A. The proposed Implementation Methodology instructs us to exclude all resources committed to load from the 7(b)(2)(D) resource stack. This exclusion is in conformance with the proposed Legal Interpretation. BPA will address parties' properly raised issues regarding the correctness of BPA's Legal Interpretation in the Draft and Final Records of Decision in this proceeding.

Q. PPC argues that BPA's decision to exclude the Mid-Columbia resources from the 7(b)(2) Case available resources is inconsistent with BPA's position on the issue in past rate proceedings. O'Meara, et al., WP-07-E-PP-9 at 8-9. Do you agree?

A. It would be more accurate to state that BPA properly reviewed its discussion of the Mid-Columbia resources in previous rate cases (which was necessary because the issue never had to be litigated to a final decision that was reflected in rates before) and BPA also reviewed parties' previous arguments regarding the inclusion of Mid-Columbia resources in the resource stack. From this review, BPA objectively determined that it had overlooked a critical element in its previous analysis.

That element regarded the correct interpretation and application of section 7(b)(2)(D) of the Northwest Power Act where the language reads: "…not committed to load pursuant to section 5(b)…" As a result of this further review, BPA has proposed to change its Legal Interpretation. This proposed change has led to a change in the proposed Implementation Methodology, which now instructs us to exclude all resources committed to load pursuant to section 5(b) from the 7(b)(2)(D) resource stack. BPA will address parties' properly raised arguments regarding the correctness of BPA's Legal Interpretation in the Draft and Final Records of Decision in this proceeding.

Q. PPC argues that BPA's proposed analytical treatment of the Mid-Columbia resources in the FY 2009 rate test is incorrect even under BPA's own proposed Section 7(b)(2) Implementation Methodology and Legal Interpretation. O'Meara, et al., WP-07-E-PP-9 at 9. Do you agree?

A. We agree that the Supplemental Proposal was not entirely consistent with the proposed Implementation Methodology due to a failure to track certain sales of the Mid-Columbia resources. Mid-Columbia resources owned by 7(b)(2) Customers and sold to other entities would be available in the 7(b)(2) Case unless sold to a customer with a 5(b) contract and dedicated to load. As a result of PPC's and WPAG's direct cases, we have applied the proposed Implementation

Methodology and have found that some Mid-Columbia resources have been erroneously excluded from the 7(b)(2)(D) resource stack.

Q. *PPC and WPAG argue that Alcoa (a non-IOU, non-preference customer, aluminum smelter company) has for many years purchased, and continues to purchase, power from Chelan PUD based on a contract for a major portion of the output of the Rocky Reach dam. O'Meara, et al., WP-07-E-PP-9 at 10; Grinberg, et al., WP-07-E-WA-05 at 24. PPC and WPAG argue that as a non-utility, neither Alcoa, Colockum nor Alcoa Power generating, Inc. have a section 5(b) contract with BPA in which they have dedicated that resource. Id. Therefore, PPC and WPAG argue that the portion of the Rocky Reach resource that is purchased by or on behalf of Alcoa is not properly excluded from the resources available in the 7(b)(2) Case even under BPA's proposed Implementation Methodology and Legal Interpretation. Id. Do you agree?*

A. We agree with PPC and WPAG's factual analysis of the Alcoa purchase, but that is not the sole determining factor. Rocky Reach is owned by Chelan PUD. Chelan does not have a section 5(b) contract with BPA and is therefore not a 7(b)(2) Customer. Therefore, according to the proposed Implementation Methodology, Rocky Reach can be included in the 7(b)(2)(D) resource stack only if it was purchased by a customer with a 5(b) contract and not dedicated to load. All other portions of Rocky Reach would not be available to be considered for inclusion in the resource stack.

Q. *PPC argues that BPA may believe that all of Rocky Reach is "dedicated to load pursuant to section 5(b)" due to the assertion that "the Mid-C resources were used in the year prior to December 5, 1980 to serve IOU firm load in the region," O'Meara, et al., WP-07-E-PP-9 at 12. However, this also appears incorrect* *since, as we described above, Alcoa has had rights to purchase the output of the Rocky Reach dam since 1957. Id. Do you agree?*

A. We do not believe that all of Rocky Reach is "dedicated to load pursuant to section 5(b)" due to the assertion that "the Mid-C resources were used in the year prior to December 5, 1980 to serve IOU firm load in the region."

Q. Because Alcoa's purchase pre-dates that Northwest Power Act, does that mean it should be included in the resource stack?

A. No. As we have stated before, there are several tests that must be met before a resource is included in the resource stack. Alcoa's purchase of Rocky Reach fails these tests, and therefore should be excluded.

Q. What are the tests you refer to?

A. The proposed Implementation Methodology instructs BPA to exclude all resources committed to load pursuant to section 5(b) from the 7(b)(2)(D) resource stack. Therefore, it must be determined that two conditions exist. First, BPA must have access to the resource in the 7(b)(2) Case. To establish this, the resource must be owned or purchased by a customer with a section 5(b) contract with BPA.

If the owner does not have a 5(b) contract and the resource output is for the owner's own use, then BPA cannot use the resource in the 7(b)(2) Case. If the owner without a 5(b) contract sells the output to a purchaser without a 5(b) contract, then BPA cannot use the resource in the 7(b)(2) Case. However, if the owner without a 5(b) contract sells the output to a purchaser with a 5(b) contract and that purchaser has not dedicated the output to load, then BPA can use the resource in the 7(b)(2) Case.

If the owner has a 5(b) contract, BPA must determine if the resource has been dedicated to load. This resolution requires another set of questions. First, BPA must examine the owner's own use of the resource to see if the "own use" portion is dedicated to load. If it is, then it will be excluded from the resource stack; if not, then it will be included. Second, if the owner has a 5(b) contract and has sold the resource, the portion that is sold is obviously not dedicated to the owner's load. In this case, BPA must determine whether the purchaser has a 5(b) contract. If it does, and the purchaser has dedicated the resource to load, then it will be excluded from the resource stack; if it is not dedicated to load, it will be included. If the purchaser does not have a 5(b) contract, the resource will be included in the resource stack.

We have displayed the foregoing analysis on a decision tree and attached it to this testimony. We propose to include this decision tree in the Implementation Methodology to assist in future rate proceedings. *See* Attachment 4. The results of the application of the decision tree to the Mid-Columbia resources in shown in Attachment 5.

Q. PPC argues that some of the contracts that were in force in 1980 under which regional IOUs purchased the output from Mid-Columbia resources have since expired. O'Meara, et al., WP-07-E-PP-9 at 14. Do you agree?

A. Yes. However, those contracts were replaced by a set of new contracts offered by the licensee. For example, Grant was required to offer new contracts to its regional purchasers and the parties have executed new contracts. There is a possible adjustment in the amount of power purchased when those contracts take effect under the new license, but a new license has not been approved by FERC at this time. The fact that certain contracts have expired does not, by itself, determine whether the resource is committed to load or not for purposes of section 5(b). These contracts are for a participant share of output from a specific resource, like Priest Rapids or Wanapum dam, and are not a commercial purchase of power on the market. The parties have a right to reoffers, so simply because a prior contract expires does not mean that a customer can remove a resource from being dedicated to load. BPA's Section 5(b)/9(c) Policy sets forth BPA's policy about how resources will be treated when contracts expire. The Policy states that a right to renewal means that when a contract terminates, the customer must exercise its right to the resource, and the resource is not lost as long as a utility can obtain a new contract for the resource it acquired prior to enactment of the Northwest Power Act and used to meet its native load. Unless the Administrator determines there is a basis for loss of the resource, the utility must continue to dedicate that resource to native load and cannot place a larger requirement on BPA. So if a power sales contract expired after enactment of the Act, if there were a follow-on contract for the same resource, this would not be treated as a loss of contract right. Instead, the follow-on purchase would also have to be dedicated to the utility's native load.

Q. PPC argues that the only 5(b) contracts that BPA purports to currently have with regional IOUs were developed in conjunction with the REP Settlement Agreements to provide physical power under those agreements. O'Meara, et al., WP-07-E-PP-9 at 14-15. Do you agree?

A. When BPA conducted the WP-02 supplemental rate case in 2000-2001, the IOUs had executed REP Settlement Agreements. Attached to the REP Settlement Agreements as exhibits were separate firm power requirements contracts offered under section 5(b) of the Northwest Power Act. These contracts were intended to be "stand alone" contracts. Under those contracts, all IOUs that purchased Mid-Columbia resources from preference customers dedicated such purchases to their own loads for purposes of calculating their net requirements. These requirements contracts have never been terminated by the parties. BPA will address parties' properly raised issues regarding the legal validity of such contracts in the Draft and Final Records of Decision. Also we previously addressed this issue in greater detail and incorporate such discussion here.

Q. PPC argues that there may be other preference customer resources that should be deemed available in the 7(b)(2) Case under BPA's proposed Implementation Methodology and Legal Interpretation, but which were excluded by BPA in its Initial Proposal. O'Meara, et al., WP-07-E-PP-9 at 12. Do you agree?

A. Yes. BPA has identified certain Mid-Columbia resources that should be included in the 7(b)(2)(D) resource stack. *See* Attachment 5.

Q. WPAG argues that BPA's position in the WP-02 and WP-07 rate cases was that the Mid-Columbia resources owned by preference customers that they had not declared to their retail load service under a section 5(b) contract with BPA were available for inclusion in the 7(b)(2) Case. Grinberg, et al., WP-07-E-WA-05 at 20. Although BPA described the treatment of these resources as "moot," it included them in the 7(b)(2) Case documentation in both the WP-02 and WP-07 rate cases. Please respond.

A. At that time, the Implementation Methodology indicated that the proper treatment for the Mid-Columbia resources was that the portions not used to serve preference customer load should be included in the resource stack. However, as WPAG notes, the issue whether this was the correct treatment was moot because no resources were required from the resource stack in the WP-02 Final Proposal. BPA's WP-02 Record of Decision stated:

> **<u>Evaluation of Positions</u>**
> In the initial proposal, BPA proposed to use resources from the resource stack in the 7(b)(2) Case, which included Mid-Columbia resources, to meet specified loads. Kaptur *et al.*, WP-02-E-BPA-34, at 12. In BPA's rebuttal testimony, however, BPA recognized that additional resources in excess of the FBS

> were not needed to meet 7(b)(2) customers' loads; therefore, it was unnecessary to use any resources from the 7(b)(2) Case resource stack in conducting the 7(b)(2) rate test. Kaptur *et al*., WP-02-E-BPA-56, at 18-19. Because BPA did not propose to use resources from the 7(b)(2) Case resource stack, including the *Mid-Columbia resources*, in conducting the 7(b)(2) rate test, this issue would not affect the development of BPA's wholesale power rates in this proceeding and *need not be addressed at this time*.
>
> ***Decision***
>
> *The issue of whether BPA should include Mid-Columbia resources in the 7(b)(2) Case resource stack is moot, because BPA will not use any resources from the resource stack, including Mid-C resources, to meet 7(b)(2) customers' loads.*

Administrator's Record of Decision, WP-02-A-02 at 13-49 to 13-50 (emphasis added). In BPA's WP-07 rate case, BPA's Record of Decision noted:

> …During the WP-07 rate proceeding, however, the litigants developed a Partial Resolution of Issues. (Evans, *et al*., WP-07-E-BPA-31, Attachment A.) This agreement provides in part:
>
> **1. 7(b)(2)**
>
> BPA will not, in any other proceeding, cite any action taken or not taken in this WP-07 proceeding as evidence of the propriety of (or precedent for) the resolution of any issue with respect to the treatment, under Section 7(b)(2), of *the Mid-Columbia resources*, conservation, uncontrollable events or secondary revenues counted as reserves. To the extent that BPA has addressed and resolved in this WP-07 proceeding any such issues, such BPA actions shall not be considered by BPA to be precedential or binding on BPA in any other proceeding. No action taken or not taken in this WP-07 proceeding with respect to any such issues shall be considered by BPA to either create an adverse inference with respect to any such issues in, or preclude any party from arguing the treatment of any such issues in, any other proceeding (whether before BPA, FERC or a court and whether or not on remand) or in any remand of a rate developed in WP-07 by FERC or a court. BPA recognizes that, in reliance on this BPA approach, the prefiled testimony labeled WP-07-E-JP6-01, WP-07-E-JP6-03, and WP-07-E-JP6-04 were not proffered into evidence in this proceeding when they would otherwise have been proffered.

(*Id.*) Due to the foregoing, BPA has not fully litigated all issues regarding Section 7(b)(2) in the WP-07 rate proceeding:

> *BPA has not litigated all legal issues regarding the inclusion of the Mid-Columbia resources in the 7(b)(2) Case resource stack. If BPA had reviewed all such issues it is possible that BPA would have changed its position from its WP-07 Initial Proposal.* Such a change would have had a dramatic effect on the Section 7(b)(2) rate step by significantly reducing the reallocation amount, and thereby reducing the PF Exchange rate and making greater REP benefits available to exchanging utilities.

WP-07 Administrator's Record of Decision, WP-07-A-02 at 10-4 to10-5. (Emphasis added.) Thus, BPA acknowledged that it might have changed its treatment of the Mid-Columbia resources in BPA's final WP-07 rates if the issue had been litigated and not been moot.

Q. *WPAG argues that BPA's approach is inappropriate because the contracts between the IOUs and the preference customer Mid-Columbia resource owners that were in place the year prior to December 5, 1980, and which provided the IOUs with contract rights to purchase the power from these resources, generally had terms that were coterminous with the original FERC licenses for these resources. Grinberg, et al., WP-07-E-WA-05 at 22. These contracts have begun to expire. Do you agree?*

A. We agree that the pre-1980 contracts have begun to expire. It is our understanding that the original contracts for Priest Rapids and Wanapum have expired and been replaced with successor contracts. It is also our understanding that the contracts for Rocky Reach have expired and been replaced with successor contracts. Based on license expiration, we would expect Wells contracts to continue until 2012. Also based on license expiration, we would expect Rock Island contracts to continue until 2028.

Q. *WPAG argues that upon the expiration of these contracts the resources in question ceased to be committed to load under section 5(b)(1)(A) due to loss of contract rights. Grinberg, et al., WP-07-E-WA-05 at 22. WPAG argues they then* *become available for the 7(b)(2) Case unless they are committed to load service by the IOU or a preference customer under a section 5(b) power contract with BPA. Id. Do you agree?*

A. No. As noted previously, BPA's Section 5(b)/9(c) Policy sets forth BPA's policy about how resources will be treated when contracts expire. The 5(b)/9(c) Policy states that as long as a utility acquired a resource prior to enactment of the Northwest Power Act and used it to meet its native load, the utility must continue to dedicate that resource to native load and cannot place a larger requirement on BPA. Furthermore, even if a power sales contract expired after enactment of the Act, if there were a follow-on contract for the same resource, this would not be treated as a loss of contract right. Instead, the follow-on purchase would also have to be dedicated to the utility's native load.

Q. WPAG argues that the following amounts of Mid-Columbia resources used to serve regional load in the year before the passage of the Northwest Power Act have not been dedicated to load under a section 5(b) power contract with BPA subsequent to the expiration of the initial contract with the resource owner. Grinberg, et al., WP-07-E-WA-05 at 23. Avista--Priest Rapids = 20.1 MW; PacifiCorp--Priest Rapids = 51.4 MW; PGE--Priest Rapids = 45.8 MW; PSE--Priest Rapids = 34.0 MW. Id. Do you agree?

A. This identified resources should not be included in the resource stack for the reasons cited in this testimony.

Q. WPAG argues that information regarding these resources was available in the spring of 2001. Grinberg, et al., WP-07-E-WA-05 at 23. Do you agree?

A. The availability of information in the spring of 2001 is not dispositive of whether a resource has been dedicated to load under section 5(b).

Q. WPAG argues that other Mid-Columbia resources have not been dedicated to load under section 5(b). Grinberg, et al., WP-07-E-WA-05 at 24-25. Effective February 11, 2005, a 4.5 percent share (14.5 aMW) of the Wells project was sold to the Colville Tribe through August 31, 2018, with this share increasing to 5.5 percent (18 aMW) thereafter. Id. The Colville Tribe has no 5(b) contract with BPA. Id. In addition, effective June 11, 2007, the Yakama Tribe was sold the following portions of the Priest Rapids project: 20 aMW from 2007 to 2009; 15 aMW from 2010 to 2015; and 10 aMW from 2016 through the end of the FERC license. Id. The Yakama Tribe has a 5(b) contract with BPA, but has not declared this resource under that contract. Id. Under BPA's approach to the treatment of Mid-Columbia resources, the output sold to these two purchasers is available for the 7(b)(2) Case. Id. Do you agree?

A. We agree that portions of Mid-Columbia resources have been sold to the Colville Tribe and the Yakama Tribe. We do not agree that both of these purchases should be included in the 7(b)(2)(D) resource stack. The Colville Tribe does not have a section 5(b) contract with BPA and the project owner, Douglas PUD, does not have a section 5(b) contract with BPA. Therefore, the Colville Tribe's purchase of Wells cannot be considered as available in the 7(b)(2) Case. The Yakama Tribe does have a section 5(b) contract and has not dedicated its purchase of Priest Rapids to load pursuant to section 5(b). Therefore, the Yakama Tribe's purchase of Priest Rapids should be included in the resource stack.

Q. WPAG argues there is a requirement in the new FERC license of the Priest Rapids project that a percentage of its output be made available periodically through an auction process. Grinberg, et al., WP-07-E-WA-05 at 25. WPAG notes in each instance the purchaser was a marketer or other entity that did not have a BPA section 5(b) contract, and did not declare such output to retail load *service. Id. WPAG argues it is reasonable to assume that marketers will continue to be the winning bidders in future auctions because they can sell this output into the most lucrative market. Id. Do you agree?*

A. Yes. The current purchaser, Highland Energy, does not have a 5(b) contract. The project owner, Grant PUD, does have a 5(b) contract. Therefore, because Grant has a 5(b) contract and has not dedicated the Highland purchase portion to load pursuant to section 5(b), the portion of the resource purchased by Highland should be included in the resource stack. Further, we agree with WPAG that it is reasonable to expect that future purchasers of the auctioned portions of Priest Rapids will be to entities without 5(b) contracts. Therefore, it is reasonable to conclude that the auctioned portions should continue to be included in the resource stack through the Five-Year Period.

Q. WPAG argues that the contracts under which the Priest Rapids power is sold contain a provision requiring that it be resold to entities with a section 5(b) contract with BPA. Grinberg, et al., WP-07-E-WA-05 at 26. WPAG argues, however, it is not clear that such purchasers are required to declare such purchase amounts under such BPA section 5(b) contract, or whether in fact such declarations have occurred. Id. WPAG notes that in the event such resource amounts have been so declared, under BPA's approach these resource amounts would not be available for the 7(b)(2) Case. Id. If they have not been so declared, they should be treated as available for the 7(b)(2) Case. Do you agree?

A. Yes. Unless it can be demonstrated that the resale purchasers have dedicated their purchase to load pursuant to section 5(b), it is reasonable to conclude that the resales should be included in the resource stack.

Q. Have you reviewed the Mid-Columbia resources in light of the proper application of the Implementation Methodology?

A. Yes. We have found that, in addition to the Yakama purchase, there are some other purchasers of Mid-Columbia resources that have 5(b) contracts and have not committed their purchase to load. We have prepared a table to indicate the proper disposition of all of the Mid-Columbia resources. The table shows how the decision tree is implemented with the final results of the decision tree are listed in Attachment 5.

Section 6: Treatment of Conservation Resources

Q. Cowlitz/Clark argue that BPA's method allows the selection of a conservation block even before the necessary investments are to be made in the real world. Schoenbeck and Beck, WP-07-E-JP17-01 at 21. As an example, the FY 2009 RAM selects the 2012 and 2013 conservation blocks in 2009. Id. Similarly it selects the 2011 block in 2010. Id. This is illogical as well, as future conservation cannot have been "purchased" (past tense) from customers. Id. Do you agree?

A. No. The Implementation Methodology instructs that we are to assume that "actual and planned resource acquisitions by BPA from 7(b)(2) Customers consistent with the Program Case, including conservation resources" are available in the 7(b)(2)(D) resource stack. *See* Implementation Methodology, WP-07-E-BPA-50, Attachment B at IM-7. There is no temporal distinction in when resources are available. That the Program Case does not plan on acquiring a resource until a future year does not constrain the 7(b)(2) Case to consider the resource as being first available in the year determined in the Program Case. As with any utility resource plan, should the need for a planned resource arise sooner than predicted, the utility will advance the date of that resource to as soon as needed. The expected online date in the resource plan does not constrain the actual online date.

Q. *APAC argues BPA's treatment of conservation imposes an inappropriate penalty on conservation because the Northwest Power Act obligates BPA to encourage conservation yet BPA's treatment of conservation in the section 7(b)(2) rate test analysis results in preference customers paying a $49.35/MWh penalty for using BPA conservation programs. Wolverton, WP-07-E-AP-1 at 63. APAC proposes that BPA's rate treatment of conservation in the section 7(b)(2) rate test should be deleted from BPA's February 2008 proposed Section 7(b)(2) Implementation Methodology. Id. Do you agree?*

A. The proposed Implementation Methodology provides that conservation resources are to be included in the 7(b)(2)(D) resource stack and, as a consequence, the effects of conservation resources are to be removed from 7(b)(2) Customer loads. The proposed Implementation Methodology is in conformance with the proposed Legal Interpretation. BPA will address parties' properly raised issues regarding the correctness of BPA's Legal Interpretation in the Draft and Final Records of Decision in this proceeding.

Further, APAC's analysis makes little sense and does not support its contention that preference customers would be better off avoiding BPA conservation programs. *See* Wolverton, WP-07-E-AP-1 at 69. APAC argues that because BPA included annual programmatic conservation in the 7(b)(2) Case resource stack, the REP net benefits were higher than in a scenario with no programmatic conservation in the resource stack. APAC took the difference in REP benefits between BPA's proposal that matched conservation savings with the cost of conservation programs and its own erroneous scenario that apparently assumed conservation savings at little or no cost and divided that amount by the actual total conservation savings achieved in the Program Case. The result of this calculation is the $49.35/MWh APAC cites as a penalty for participating in BPA conservation programs. APAC's argument seems to be that if conservation savings can be acquired at little or no cost in the 7(b)(2) Case, the 7(b)(2) rate test trigger would be larger and the REP benefits would be smaller. It is a significant logical stretch to conclude that by changing the load/resource balance and the resource availability in the 7(b)(2) Case by assuming away most of the cost of conservation programs one can make actual BPA conservation programs more or less cost effective.

It is true that changing the load/resource balance and the resource cost and availability in the 7(b)(2) Case in ways that are not supported by the Implementation Methodology can result in fewer calculated REP benefits. However, we must conduct the 7(b)(2) rate test in a manner that is supported by the Implementation Methodology.

Q. *APAC notes that in the section 7(b)(2) rate test, BPA proposes to augment the 7(b)(2) Customer load to account for conservation purchased in the past. Wolverton, WP-07-E-AP-1 at 62. APAC argues this treatment is inconsistent with law and therefore all references to load augmentation due to conservation should be removed from the section 7(b)(2) rate test. Id. Do you agree?*

A. The proposed Implementation Methodology provides that conservation resources are to be included in the 7(b)(2)(D) resource stack and, as a consequence, the effects of conservation resources are to be removed from 7(b)(2) Customer loads. This same treatment of including conservation resources in the resource stack and increasing the 7(b)(2) Case loads has been followed since 1985 and the preference customers have not raised this issue before this time. The proposed Implementation Methodology is in conformance with the proposed Legal

Interpretation. BPA will address parties' properly raised issues regarding the correctness of BPA's Legal Interpretation in the Draft and Final Records of Decision in this proceeding.

Q. *APAC notes the manner in which the Section 7(b)(2) Implementation Methodology and RAM model treat conservation. Wolverton, WP-07-E-AP-1 at 66-67. APAC argues that "BPA confiscates the conservation" because the annual historic amount of conservation achieved through BPA's programs in the FY 2009 rate-setting process, a total of 538.2 aMW after adjustment for losses, appears in the load-resource balance as an obligation, pursuant to Implementation Methodology. Id. APAC argues that there is no financial recognition in the RAM for the conservation stripped from preference customers and added to their load obligation. Id. Do you agree?*

A. No. APAC's argument is irrelevant. The rate test contains a number of assumptions for the 7(b)(2) Case that do not necessarily reflect the reality of the Program Case. For example, DSI loads are served by their local utilities rather than BPA. Another assumption is that the REP does not exist. APAC complains about another assumption made for the 7(b)(2) Case, that is, that resource acquisitions are performed differently than in the Program Case. Similarly, the 7(b)(2) Case assumes that resources owned or purchased by 7(b)(2) Customers but not dedicated to load are available to be used by BPA to serve 7(b)(2) Customer loads despite their actual use in the Program Case. Another of these assumptions is that resources BPA has purchased that are not FBS resources are to be put into the 7(b)(2)(D) resource stack and drawn upon when necessary and in least cost order. It does not matter how those resources have been purchased in the Program Case.

A hypothetical example illustrates this. Suppose BPA has acquired a non-FBS resource in the Program Case and the resource has been completely paid off. In such a case, there is no cost of this resource in the Program Case, yet the output of the resource is available to serve loads in the Program Case. However, because the resource is not an FBS resource, the Implementation Methodology instructs that this resource is to be included in the 7(b)(2)(D) resource stack and the cost of the resource (independent of the fact that BPA has paid it off) is identified in the event the resource is drawn upon to serve 7(b)(2) Customer loads. Therefore, the issue APAC complains about is a natural outcome of the 7(b)(2) Implementation Methodology.

Q. *APAC argues that all of the costs of conservation that BPA removes when it augments load either have been paid for or are currently included in section 7(b)(2) rates. Wolverton, WP-07-E-AP-1 at 67. APAC argues that the amount that has been revenue financed has already been included in rates in past rate cases – that is, it has been charged to ratepayers in the rate period that covers the year of the conservation program. Id. The revenue-financed component of conservation costs is confiscatory for purposes of the section 7(b)(2) rate test. Id. Of the amount financed over the 15- or 20-year periods, the conservation programs brought on in the early years largely have been paid for. Id. The unamortized amount is also removed by the RAM. Id. However, the remaining payments are contained in BPA's current program conservation costs in the Program Case, which becomes the section 7(g) adjustment. Id. That section 7(g) adjustment is exempted from the rate test; that is, preference customer rates contain those costs despite section 7(b)(2) protection. Id. APAC argues that although BPA states in the Implementation Methodology that the conservation* *has not been paid for because it has not yet been chosen from the resource stack, the conservation has in fact been paid for. Id. Please respond.*

A. In the 7(b)(2) Case, resources included in the 7(b)(2)(D) resource stack are not paid for until they are chosen to meet 7(b)(2) Customer load in excess of the available FBS. To accomplish this, the costs of past acquisitions have been removed from the costs included in the 7(b)(2) Case rates. Therefore, they have not yet been paid for in the 7(b)(2) Case.

Q. APAC argues that after BPA augments the load in the amount of the energy saved from the historical conservation programs, BPA offers the same conservation programs back to the section 7(b)(2) load insofar as it is needed to serve that load. Wolverton, WP-07-E-AP-1 at 68. Moreover, BPA inflates the 1997 costs to 2009 levels, raising the price to repurchase a program that has been paid for. Id. APAC argues that, in summary, the preference customers under the section 7(b)(2) rate test must buy back conservation they had already paid for in rates (or are in the process of paying for) to serve loads that have been artificially augmented. Id. APAC argues that the BPA modeling and rate test treatment of conservation double-charges preference customers. Id. Do you agree?

A. No. As explained in the prior two answers, this is a natural consequence of the way the 7(b)(2) Case is constructed.

Q. APAC argues that the resulting impact on BPA's conservation programs is that preference customers would be better off financially by avoiding BPA conservation programs and operating their own conservation programs at the utility level – and by doing so, contributing to the Northwest Power Act's conservation goals. Wolverton, WP-07-E-AP-1 at 68. APAC also argues that BPA imposes a $49.35 penalty for conservation. Id. at 69. Do you agree?

A. No. As noted above, APAC's faulty analysis is based on the apparent premise that conservation savings in the 7(b)(2) Case can be acquired for little or no cost. APAC took the difference in REP benefits between BPA's proposal that matched conservation savings with the cost of conservation programs and its own erroneous scenario that assumed conservation savings were a retail utility cost and divided that amount by the actual total conservation savings achieved in the Program Case. The result of this calculation is the $49.35/MWh APAC cites as a penalty for participating in BPA conservation programs. APAC's argument seems to be that if conservation savings can be acquired at little or no cost to the PF rate in the 7(b)(2) Case, the 7(b)(2) Case rate will be lower, the 7(b)(2) rate test trigger would be larger, and the REP benefits would be smaller. We do not argue with the mathematics behind APAC's calculation of the $49.35/MWh. We do however, believe that APAC's "nearly free lunch" assumption about conservation savings in the 7(b)(2) Case is unrealistic.

Furthermore, BPA has been modeling conservation in this manner since 1985, the first year the 7(b)(2) rate test was performed. APAC has provided no evidence that this treatment of conservation in the rate test has reduced participation in BPA's conservation programs in the past 23 years. We know of no evidence of such an effect either. In fact, it is generally accepted that the Northwest Power Act has increased the use of conservation programs from what they would have been without the Act. Therefore, the observable preference for regional utilities is and has been to participate in BPA's conservation programs without regard to any real or supposed effect their participation may have on REP benefits.

Q. APAC argues that BPA should not be promulgating a proposal for the section 7(b)(2) rate test that has a significant penalty for using BPA's conservation *programs and hinders the conservation objectives of the Northwest Power Act. Wolverton, WP-07-E-AP-1 at 71. APAC argues that the changes it recommends have been covered previously in its recommendations for correcting the definition of section 7(b)(2) loads in the Implementation Methodology, which would provide a simple fix that would eliminate the penalty on conservation. Id. Do you agree?*

A. No. The proposed "simple fix" is contrary to the Implementation Methodology. Even if APAC were correct that the rate test treatment of conservation resulted in more utilities turning from BPA to self-provision, which has not occurred, that result cannot substitute for the proper implementation of the rate test.

Q. Cowlitz/Clark argue that BPA's conservation adjustment to general requirements is not called for by the section 7(b)(2) directives because the only change in general requirements that section 7(b)(2) addresses directly is in section 7(b)(2)(A) that BPA is to assume that the general requirements include the within or adjacent DSI loads mentioned above. Schoenbeck and Beck, WP-07-E-JP17-01 at 16. Do you agree?

A. No. BPA will address parties' properly raised issues on whether BPA's conservation adjustment is consistent with the section 7(b)(2) rate directives in the Draft and Final Records of Decision in this proceeding. However, annual programmatic conservation resources are properly included in the 7(b)(2) Case resource stack. Because these conservation resources are available to serve load in the 7(b)(2) Case after the FBS resources are exhausted, the starting 7(b)(2) load forecast cannot already have been reduced by these same programmatic conservation resources. In summary, these resources are in the resource stack and, if they are waiting in the stack to be used to serve load, they cannot have already been used to reduce the starting 7(b)(2) Customer loads.

BPA will address parties' properly raised legal arguments regarding whether BPA's conservation adjustment is consistent with the section 7(b)(2) rate directives in the Draft and Final Records of Decision in this proceeding.

Q. *Cowlitz/Clark note that BPA states in its proposed Legal Interpretation of Section 7(b)(2) that changing the general requirements of preference customers to remove the effect of conservation and placing conservation in the 7(b)(2) resource stack is necessary to avoid double counting conservation costs in the 7(b)(2) Case. Schoenbeck and Beck, WP-07-E-JP17-01 at 16-17. Cowlitz/Clark argue the math behind the double-counting argument is incorrect. Id. BPA reduces the Program Case costs by the cost of the applicable section 7(g) costs, which in this case consist entirely of conservation costs, prior to comparing the Program Case power costs with 7(b)(2) Case power costs, which do not contain those same conservation costs unless conservation is drawn from the 7(b)(2) resource stack. Id. If the rate for 7(b)(2) Case power costs exceeds the rate for Program Case power costs, then BPA designs the PF Preference rate to recover the Program Case power costs plus the applicable conservation costs. Id. On the other hand, if the rate for the Program Case power costs exceeds the rate for the 7(b)(2) Case power costs, then BPA converts the difference between the two rates into a dollar amount and BPA subtracts that dollar amount from the sum of the Program Case power cost plus the applicable conservation costs. Id. BPA then designs the PF Preference rate to recover the resulting amount. Id. Therefore, BPA's conservation costs, which are the only applicable section 7(g) costs in this case, are fully recovered from preference customers irrespective of what happens in the 7(b)(2) Case. Id. If the conservation costs are also allowed to creep back into the 7(b)(2) Case as power costs, as is proposed by BPA, then those costs are more than double-counted. Id. Do you agree?*

A. No. Cowlitz/Clark's argument confuses general ratemaking with the comparison of Program Case and 7(b)(2) Case rates in the 7(b)(2) rate test. Cowlitz/Clark conclude that because conservation costs are fully recovered in the ratemaking process, these costs cannot be included in the 7(b)(2)(D) resource stack and to do so will "double count" of these costs.

The ratemaking treatment of conservation is different in the 7(b)(2) Case than the Program Case. In the Program Case, all conservation costs in the annual revenue requirements are allocated to rates, including the unbifurcated PF rate. In the 7(b)(2) rate test, this unbifurcated PF rate is adjusted by removing the Applicable 7(g) Costs (conservation costs) that had been allocated to the rate. This adjusted unbifurcated PF rate is then compared to the 7(b)(2) Case PF rate. In the 7(b)(2) Case, no conservation costs are in the annual revenue requirements. However, each annual programmatic conservation resource is in the 7(b)(2) resource stack and can be included in the costs recovered by the 7(b)(2) PF rate if that conservation resource is chosen to serve load over and above the load served by the FBS resources. This different treatment afforded conservation costs in the two cases used in the 7(b)(2) rate test does not affect the amount of actual conservation costs recovered by BPA's actual rates. Cowlitz/Clark seem to acknowledge this by noting that BPA's conservation costs, which are the only applicable section 7(g) costs in this case, are fully recovered from preference customers irrespective of what happens in the 7(b)(2) Case. Schoenbeck and Beck, WP-07-E-JP17-01 at 17. However, Cowlitz/Clark then makes the apparently contradictory statement that if the conservation costs are also allowed to creep back into the 7(b)(2) Case as power costs, as is proposed by BPA, then those costs are more than double counted. Schoenbeck and Beck, WP-07-E-JP17-01 at 17.

Q, *Cowlitz/Clark argue that BPA doesn't need the conservation resources in the section 7(b)(2) resource stack. Schoenbeck and Beck, WP-07-E-JP17-01 at 17. The way that BPA performs the rate test assures that preference customers pay for the conservation costs in their rates irrespective of section 7(b)(2). Id. The conservation measures have in fact reduced preference customers' power requirements from what they might otherwise have been. Id. But section 7(b)(2) addresses "the power costs for general requirements," and "general requirements" is defined as "electric power purchased from the Administrator." Id. The resources mentioned in section 7(b)(2)(D) are resources required "to meet the remaining general requirements" of preference customers. Id. As rate analysts, Cowlitz/Clark interpret this language to say that the resources whose costs are to be allocated to the section 7(b)(2) power cost, including the resources addressed in section 7(b)(2)(D), are resources like the FBS that supply power that preference customers can purchase from BPA. Id. Conservation installed at consumers' homes and businesses is a resource, but does not supply power that preference customers can purchase from BPA to meet their general requirements remaining after those conservation induced load reductions. Id. Do you agree?*

A. We fail to see the connection that Cowlitz/Clark attempts to make between the fact that conservation costs in its revenue requirement are recovered by rates and the fact that programmatic conservation resources are made available to serve load in the 7(b)(2) Case of the 7(b)(2) rate test. On one hand, BPA sets rates in its rate proceedings to recover its costs, including the costs of its conservation programs. On the other hand, in the hypothetical world of section 7(b)(2), BPA's programmatic conservation is a Type 1 resource under the proposed 7(b)(2) Implementation Methodology. *See* Implementation Methodology, WP-07-E-BPA-50, Attachment B at IM-7. Real world revenue sufficiency and the construction of a hypothetical world in the 7(b)(2) rate test do not impinge on each other. Neither the Implementation Methodology or the Legal Interpretation draw a distinction between resources that conserve power and resources that supply power; both are considered resources. BPA will address parties' properly raised legal issues in the Draft and Final Record of Decision in this preceding.

Q. *Cowlitz/Clark argue that conservation resources should not be included in the 7(b)(2) resource stack because they cannot meet the general requirements (i.e. supply power to be purchased by preference customers). Schoenbeck and Beck, WP-07-E-JP17-01 at 18. Do you agree?*

A. No. The Implementation Methodology directs us to include conservation resources in the 7(b)(2) resource stack. *See* Implementation Methodology, WP-07-E-BPA-50, Attachment B at IM-8 and IM-9. BPA will address parties' properly raised legal arguments regarding section 7(b)(2) in the Draft and Final Records of Decision in this proceeding.

Q. *The IOUs argue that in performing the section 7(b)(2) rate test, BPA subtracts its current conservation costs from the Program Case costs and excludes an identical amount from the 7(b)(2) Case costs, then includes what it considers to be non-obsolete conservation as a resource assumed to be available in the 7(b)(2)(D) resource stack. LaBolle, et al., WP-07-E-JP6-08 at 5. The IOUs argue that, as a result, some or all of BPA's conservation may not be drawn from the resource stack, and BPA's conservation costs included in its rates may well differ from the costs of conservation drawn from the 7(b)(2)(D) resource stack. Id. Consequently, BPA may project 7(b)(2) Case costs that do not include, and that are inadequate to recover, BPA's actual conservation costs. Id. Do you agree that BPA's treatment of conservation in the 7(b)(2) rate test may result in the under-recovery of actual costs?*

A. No. The 7(b)(2) Case in a given rate proceeding has the same costs and loads as the Program Case of that rate proceeding, modified to give effect to the Five Assumptions. Conservation resources being available in the resource stack to serve load least-cost-first may result in different conservation costs in the 7(b)(2) and Program Cases, but this treatment of conservation is directed by the proposed Implementation Methodology. In any event, it is the differences in costs per load (rates) between the Program and 7(b)(2) Cases that is the essence of the 7(b)(2) rate test. The results of the 7(b)(2) rate test have no effect on overall cost recovery in a rate proceeding. The 7(b)(2) rate test is just one of many ratemaking steps in BPA's rate proceedings. If the test triggers, then a reallocation of costs between rate pools is indicated. In general terms, this reallocation does not change the overall revenue requirement and does not affect actual cost recovery.

To reiterate, we rely upon the proposed Implementation Methodology to construct the 7(b)(2) Case, including the treatment of conservation costs. The proposed Implementation Methodology is consistent with the proposed Legal Interpretation. BPA will address parties' properly raised legal arguments regarding whether the proposed Legal Interpretation correctly interprets the Northwest Power Act in the Draft and Final Records of Decision in this proceeding.

Q. The IOUs argue that if BPA excludes conservation costs from the 7(b)(2) Case costs except to the extent that conservation resources are drawn from the 7(b)(2) Case resource stack, BPA conservation spending may increase the section 7(b)(2) trigger amount, depending upon the cost of resources drawn from the 7(b)(2) Case resource stack. LaBolle, et al., WP-07-E-JP6-08 at 5. Under BPA's approach, BPA's actual conservation costs may disproportionately burden the PF

Exchange rate (and other rates, if BPA were to allocate any section 7(b)(2) trigger amount to them). Id. This is a perverse result for which BPA offers no explanation. Id. Do you agree?

A. No. The IOUs misunderstand the treatment of conservation costs in the 7(b)(2) rate test. The IOUs seem to be arguing that if the conservation resources taken from the resource stack in a given rate proceeding are cheaper than the actual conservation costs of that rate proceeding, the section 7(b)(2) rate test trigger may increase. The fact is that conservation costs are removed from the adjusted Program Case PF rate that is compared with the 7(b)(2) Case PF rate in the rate test. Therefore, the zero conservation costs in the adjusted Program Case rate can never be greater than the conservation costs in the 7(b)(2) Case PF rate. Because BPA's actual conservation costs are excluded from the 7(b)(2) rate test, they cannot disproportionately burden, or burden in any way, those rates that are affected by a 7(b)(3) reallocation made necessary by a non-zero 7(b)(2) rate test trigger.

To reiterate, we rely upon the proposed Implementation Methodology to construct the 7(b)(2) Case, including the treatment of conservation costs. The proposed Implementation Methodology is consistent with the proposed Legal Interpretation. BPA will address parties' properly raised legal arguments regarding whether the proposed Legal Interpretation correctly interprets the Northwest Power Act in the Draft and Final Records of Decision in this proceeding.

Q. The IOUs note BPA assumes that (i) BPA's conservation costs may be excluded from the 7(b)(2) Case costs (although the Initial Proposal assumes conservation may be drawn from the resource stack) and (ii) the 7(b)(2) Case costs to be projected are the costs of meeting the 7(b)(2) Case general requirements of the

PF Preference rate customers plus an amount of load equal to conservation load reduction by the PF Preference rate customers. LaBolle, et al., WP-07-E-JP6-08 at 6. The IOUs argue the following results from BPA's treatment of conservation: BPA's Program Case projects amounts to be charged that include $188.4 million of average annual conservation costs over the Five-Year Period, however, BPA's 7(b)(2) Case in effect includes only $118.4 million of average annual conservation costs over the Five-Year Period. Id. Please respond.

A. We do not agree with the IOUs' characterizations. First, as they state, we have excluded conservation costs from the 7(b)(2) Case. Second, we have included conservation resources in the resource stack. Third, we have increased the 7(b)(2) Customer loads in the 7(b)(2) Case for FY 2009 by the amount of conservation resources that have occurred prior to the start of the rate test period that were not obsolete (FY 1994-2008), totaling 520.7 aMW, together with the amount of billing credit resources included in the stack of 17.5 aMW, for a total increase in 7(b)(2) Case loads of 538.2 aMW at the start of the rate test period. Fourth, the cost of conservation over the Five-Year Period includes an annual average of $271.1 million of conservation costs in the 7(b)(2) Case. The IOUs' figure of an annual average of $118.4 million is incorrect. In comparison, the annual average amount of conservation costs for the Five-Year Period in the Program Case amounted to $166.6 million. This cost and load information was outlined in the Supplemental Proposal. Thus, the annual average conservation costs in the 7(b)(2) Case exceed the annual average Program Case costs by $104.5 million.

Conservation resources in the 7(b)(2) Case are priced differently than in the Program Case. In the Program Case, the conservation costs are the expensed costs for each year's conservation program plus the amortization expense associated with prior years' conservation programs. Total Program Case conservation costs ranged from $159 million in FY 2009 to $169 million in FY 2013. In the Program Case, conservation operating expenses other than amortization expense range from $108-114 million dollars per year during the rate test period and they comprise approximately 66 percent of total conservation expenditures. The recovery of amortization expense in the Program Case takes the place of including an increment of debt service for conservation bonds outstanding. The amortization expense in the Program Case revenue requirement consists of three different amortization treatments for prior and projected capitalized conservation expenditures. Program Case conservation amortization expense ranges from $51-63 million per year and they comprise 34 percent of the total conservation expenditures. Capitalized conservation investments relating to the years FY 1982-2001 (Legacy Conservation Investments) were amortized over 20 years. Thus, the Program Case Revenue requirement for FY 2009 contains amortization expense associated with capitalized Legacy Conservation Investment for the years FY 1989-2001. Capitalized conservation investments relating to the years FY 2002-2007 (ConAug Conservation Investments) were amortized over a declining 10-year time period. Capitalized FY 2002 conservation investments were amortized over 10 years, while FY 2007 conservation investments were amortized over four years. All ConAug conservation investments are fully amortized by the end of FY 2011 in the Program Case. Capitalized conservation investments relating to the years FY 2007-2013 (Conservation Acquisitions) are amortized over a five-year time period.

In comparison, in the 7(b)(2) Case, conservation expenses from the resource stack for FY 2009 comprise the expensed operating year costs for the years FY 1994-2005, 2009, and FY 2012-2013 along with the debt service associated with the capitalized conservation expenditures for those respective years. The debt maturity period for capitalized conservation costs is 20 years for conservation investments relating to FY 1982-2001 and 15 years for conservation investments relating to FY 2002-2013. Debt service in the 7(b)(2) Case assumes mortgage type financing (decreasing interest/increasing principal payments over the term). In FY 2010-2013 there are no conservation program operating expenses associated with the investments chosen in FY 2009. The fixed annual level of debt service associated with the 15- or 20-year debt term associated with the year of the investment continues during the remaining years of the rate test period. The 7(b)(2) Case first-year operating expenses amounted to $700.8 million for FY 2009 and then ranged from $172.6 million in FY 2010 to $0 in FY 2013. The debt service for FY 2009 amounted to $57.7 million and increased to $73.5 million by FY 2013.

As one can see from this synopsis, the treatment of conservation costs is very different between the two Cases. In the Program Case there is a stable amount of operating expense ($159 to $169 million) in all years of the rate test period. In contrast, there is a much larger up-front amount of combined operating expense associated with each fiscal year's conservation investment in the first year of the rate test period ($700,809,000), which decreases substantially from the first year amounts, to $0 in FY 2013 in the 7(b)(2) Case. In the Program Case, amortization expense ranges from $51-63 million associated with capitalized conservation investments incurred during FY 1989-2013 (replacement for debt service requirements) while in the 7(b)(2) Case there is no amortization expense. Debt service related to the specific conservation investments chosen for the year selected and for each subsequent year of the rate test period ranged from $58-74 million in the 7(b)(2) Case.

Therefore, the fact that conservation costs in the 7(b)(2) Case exceed the conservation costs in the Program Case should not be surprising. It is a natural result of the manner in which the 7(b)(2) Case is constructed.

Q. *The IOUs describe another result of BPA's treatment of conservation: BPA's Program Case projects combined general requirements that, by the end of the Five-Year Period (2013), are approximately 703 aMW lower due to investing in conservation. LaBolle, et al., WP-07-E-JP6-08 at 6. However, BPA's 7(b)(2) Case in effect includes only 672 aMW of average annual BPA conservation by the end of the Five-Year Period. Id. Please respond.*

A. The IOUs are correct that the total non-obsolete conservation up to the end of the Five-Year Period (FY 2013) is approximately 703 aMW and that the 7(b)(2) Case PF load forecast was increased by the forecast of non-obsolete conservation. The IOUs are also correct that the amount of programmatic conservation resources selected from the 7(b)(2) Case resource stack was about 672 aMW. These conservation-related variables are different; one is all conservation conducted in the Program Case and the other is the conservation selected from the 7(b)(2) resource stack. The fact that they have different values is not surprising. The amount of conservation selected from the stack is less than the total conservation acquired in the Program Case for two reasons. First, the 7(b)(2) Case has more FBS resources available to serve PF load than does the Program Case. *See* Supplemental Section 7(b)(2) Rate Test Study and Documentation, WP-07-E-BPA-50A at 30. Second, programmatic conservation resources are not the only resources selected from the 7(b)(2) resource stack. *See* Supplemental Section 7(b)(2) Rate Test Study and Documentation, WP-07-E-BPA-50A at 31.

Q. *The IOUs argue that BPA increases the combined general requirements of the PF Preference rate customers in the 7(b)(2) Case by an amount of load that was not* *reduced by conservation investments. LaBolle, et al., WP-07-E-JP6-08 at 7. For example, the Supplemental Proposal increases the combined general requirements of the PF Preference rate customers in the 7(b)(2) Case by 703 aMW of additional load. Id. Thus, for purposes of the 7(b)(2) Case, BPA assumed that the combined general requirements of the PF Preference rate customers in the 7(b)(2) Case would be increased by a load roughly equivalent to a load the size of Portland, Oregon, which assumption significantly increased the combined general requirements of such customers in the 7(b)(2) Case. Id. Please respond.*

A. The IOUs have correctly characterized the 7(b)(2) Case. The 7(b)(2) Case is different than the Program Case. The 7(b)(2) Case assumes a different selection process for resources than the Program Case. As a part of the procedure to allow for differences in resource selections, conservation is first removed from loads and included in the resource stack. Then, when necessary to meet 7(b)(2) Customer load in excess of the FBS, resources are drawn in least-cost-first order. The fact that the load differential between the two Cases is about the same size as the city of Portland is not material (other than demonstrating the success of BPA's conservation efforts). It is a result of carrying out the Northwest Power Act's directives pertaining to how the rate test is to be conducted as outlined in the Implementation Methodology.

Q. The IOUs argue that, in short, BPA should not increase the combined general requirements of the PF Preference rate customers in the 7(b)(2) Case but rather should include all conservation costs in the section 7(b)(2) Costs. LaBolle, et al., WP-07-E-JP6-08 at 7. Do you agree?

A. No. The proposed Implementation Methodology prescribes how to treat conservation in the 7(b)(2) Case, including the adjustment of 7(b)(2) Customer loads and the exclusion of conservation costs from the 7(b)(2) Case unless selected from the resource stack. The proposed Implementation Methodology is consistent with the proposed Legal Interpretation. BPA will address parties' properly raised legal arguments regarding whether the proposed Legal Interpretation correctly interprets the Northwest Power Act in the Draft and Final Records of Decision in this proceeding.

Q. The OPUC argues that BPA should adopt its recommendation to return to BPA's 1984 Methodology for treatment of applicable 7(g) costs. Hellman and McGovern, WP-07-E-PU-1 at 28. If BPA returns to its former treatment then it is correspondingly reasonable to go forward with BPA's proposed treatment of conservation resources. Id. Alternatively, BPA should assume the same conservation resources are in place in both the Program Case and 7(b)(2) Case and the costs of those resources are included in the 7(b)(2) Case and excluded in the Program Case. Id. In this latter remedy, no adjustment to loads in the 7(b)(2) case would be necessary. Id. Do you agree?

A. No. As stated above, there is no conflict on this issue between the 1984 Implementation Methodology and the proposed Implementation Methodology. As a result, there is nothing for BPA to "return to." According to both Methodologies, the possibility that there may be differing amounts of conservation between the Program Case and the 7(b)(2) Case is clearly contemplated.

Section 7: Verification and Documentation of Resources and Their Costs, and Modeling of Resource Costs

Q. The OPUC argues BPA's modeling appears to allow each year of the study period to be independent in that it can call on a resource to be used to meet load, *(i.e., is called from the resource stack), and yet in the following year the resource may or may not be on line. Hellman and McGovern, WP-07-E-PU-1 at 26. Id. The OPUC argues that the choice of resources available, and the need for resources in 2012, is not dependent on model resource selections in 2011. Id. Do you agree?*

A. No. The OPUC misunderstands how the RAM works in this instance. Although there are not any situations where this occurs in this rate proposal, should the RAM select a resource from the stack in any year of the Five-Year Period, that resource will remain available for all remaining years of the Five-Year Period, even if loads decrease in a subsequent year. The same is true even if a cheaper resource becomes available in a later year, although the way the RAM is currently structured, that is not possible. This treatment results from the instructions in the proposed Implementation Methodology, which says "[h]owever, once brought online, the resource will remain online throughout the Five-Year Period, even if loads are lower in subsequent years." *See* Proposed Implementation Methodology, WP-07-E-BPA-50, Attachment B at IM-8.

Q. The OPUC is concerned that BPA could underestimate the costs of the 7(b)(2) Case by assuming unlimited flexibility in meeting 7(b)(2) Customer loads. Hellman and McGovern, WP-07-E-PU-1 at 26. To allow resources to be available and selected in one study year, and yet allow the resource costs to be avoided in full the following year, is unrealistic and illogical. Id. Further, in the Program Case, we do not have perfect knowledge and conservation resource decisions are made without that advantage. Id. In the 7(b)(2) Case, it appears that conservation resource selection has unlimited flexibility and perfect knowledge. Id. This contrasting circumstances, and greater need for resources *under the 7(b)(2) Case, will bias the 7(b)(2) Case costs downwards. Id. Do you agree?*

A. Although there is some degree of "perfect knowledge" in the rate test modeling, the example cited by the OPUC is not an example of such knowledge. As explained previously, the RAM does not presume "unlimited flexibility" in meeting 7(b)(2) Customer loads. First, the proposed Implementation Methodology instructs that "[t]he Type 1 and Type 2 resources will be assumed to come online to meet the remaining General Requirements of the 7(b)(2) Customers after FBS service in order of least cost first." *See* Proposed Implementation Methodology, WP-07-E-BPA-50, Attachment B at IM-8. The current modeling of this instruction brings on the entire next resource, whether or not the total resources with the addition exceed the total General Requirements. This results in surplus power available in the 7(b)(2) Case. Second, as explained above, should loads decline in subsequent years, the selected resources remain online, also creating surplus power in the 7(b)(2) Case. In both instances, any surplus power is assumed to be sold. In such cases, the excess resources will be assumed to be sold at the average cost of all the excess resources and the revenues credited to the 7(b)(2) Case rates. *See* Proposed Implementation Methodology, WP-07-E-BPA-50, Attachment B at IM-8.

Q. The OPUC recommends BPA revise its modeling to either: (a) require a resource, once it is called upon, to remain in the resource stack through the remaining 7(b)(2) study period, or (b) include the entire cost of the resource (expense all capital costs) whenever a resource is chosen for service from the resource stack. Hellman and McGovern, WP-07-E-PU-1 at 27. Do you agree?

A. As indicated above, the Supplemental Proposal has already implemented choice (a), as have all prior rate tests.

Q. *The OPUC argues that the issue of perfect knowledge in the 7(b)(2) Case also applies to the issue of how conservation is handled. Hellman and McGovern, WP-07-E-PU-1 at 27. In the 7(b)(2) Case, BPA raises the loads associated with conservation acquisition and then allows the model to acquire only that amount of conservation that is needed and least cost. Id. The results of the analysis are then compared to the Program Case. Id. This provides the 7(b)(2) Case with a very distinct advantage that does not exist with the Program Case, namely, the ability to have perfect knowledge in choosing which conservation resources to add and at what time. Id. The "cost" of not having perfect knowledge in the Program Case for conservation already acquired is borne by residential and small farm customers of the IOUs. Id. This clearly seems unfair and not likely the intent of the 7(b)(2) rate test. Id. Do you agree?*

A. We are not in a position to label the instructions of Congress as unfair. This situation of "perfect knowledge" is how we are instructed to perform the rate test by the Implementation Methodology and as it is currently interpreted by the Legal Interpretation. As stated above, the ability to bring on just enough resources to meet load is a situation contemplated by both the 1984 Implementation Methodology and the proposed Implementation Methodology.

Q. *The IOUs argue that the Supplemental Proposal does not describe the justification and evidence relied upon for the resources, costs, or other information included in the 7(b)(2)(D) resource stack. LaBolle, et al., WP-07-E-JP6-08 at 8. Do you agree?*

A. Not entirely. The resource stack information used for the Supplemental Proposal was unchanged from the resource stack information used in the WP-07 Final Proposal, *see* Section 7(b)(2) Rate Test Study, WP-07-FS-BPA-06, with the exception that Mid-C Hydro resources were excluded and a number of vintage years of conservation were considered to be obsolete and not available for meeting 7(b)(2) Customer load. This document is a part of the WP-07 record, which the Supplemental Proposal is supplementing.

Appendix B of the Section 7(b)(2) Rate Test Study, WP-07-FS-BPA-06, outlined the resource stack resources including: their identification; year placed in service; the available energy; the amount of capital expenditures to be financed and the applicable interest rate; the annual operations and maintenance costs; annual fuel cost, when applicable; capacity factor; the life of the resource and debt maturity period; and the annual debt service amount (annual capital cost). Information regarding the discounting of costs and their unit costs was also outlined.

Appendix D of the Section 7(b)(2) Rate Test Study, WP-07-FS-BPA-06, presented a comprehensive review and documentation of the historical conservation costs that were in the resource stack. This analysis outlined the historical amounts that were expensed and capitalized and provided explanations for the adjustments that were made to expenditures and savings (in aMWs) to arrive at the conservation savings amounts that could be counted on to serve 7(b)(2) Customer load. The historical years of vintage conservation investments that were not obsolete at the start of the FY 2002 Lookback period were FY 1991-2004. The years of projected conservation expenditures and savings for FY 2005-2013 were also presented and discussed in Appendix D. Thus, the justification for these vintage years of historical and projected conservation costs have been thoroughly presented on the record since the WP-07 Final Proposal.

The IOUs are correct that the same level of justification and documentation for non-conservation resources was not presented in the

Supplemental Proposal. This information was presented in Responses to Data Request Nos. JP6-BPA-1, 2, 3, 5, and 34, as outlined below.

Q. The IOUs argue that on March 30, 2008, BPA had not yet responded to data requests seeking such information. LaBolle, et al., WP-07-E-JP6-08 at 8. The IOUs submitted several data requests regarding the costs of resources in the 7(b)(2)(D) resource stack. Id. Please respond.

A. We responded late to Data Request Nos. JP6-BPA-1, 2, 3, 5, and 34 on April 7, 2007. As outlined above, the documentation for non-obsolete conservation resources at the start of the FY 2002-2006 Lookback period comprising FY 1991-2013 or 23 out of 30 (77 percent) of Type 1 and 2 resources that were available to meet 7(b)(2) customer loads was available on the record since July 2006. We will update the adjusted expenditures and savings amounts for FY 2005-2007 conservation resources, which were previously forecast amounts, for the actual historical results based on the FY 2008 Conservation Resource Energy Data, the annual "Red Book" publication, which should become available in May 2008. We will also update budgeted expenditures and savings projections for FY 2008 - 2013 based on the most current projections that are available in preparing the final Supplemental Proposal. Preliminary budget numbers for conservation expenditures as well as other areas of BPA's operations will be presented in Integrated Program Review workshops for BPA's customers, constituents, tribes and other stakeholders. The Integrated Program Review process will start in May 2008. Final budget decisions that will be the outcome of that process should be available to inform the final Supplemental Proposal. The actual historical amounts and revised budget projection amounts will be adjusted in the same manner that is documented in Appendix D of the Section 7(b)(2) Rate Test Study, WP-07-FS-BPA-06. Our purpose in updating these amounts is to help ensure that the expenditures and savings amounts, and assumptions that are used to develop the 7(b)(2) Case resource stack amounts, are consistent with the costs and assumptions reflected in the Program Case for FY 2005-2013. For the final Supplemental Proposal, we will provide an appendix that updates the conservation resource cost information presently contained in Appendix D of the Section 7(b)(2) Rate Test Study, WP-07-FS-BPA-06.

The current amounts capitalized and expensed historical and projected conservation expenditures expressed in the nominal dollars of the year that they were incurred, along with additional tables expressing these amounts in 1980 dollars as well as 2007 dollars are presented in Attachment 6, Subpart 7.

In responding to the IOUs' data requests listed above, we presented updated capital and operating expenditure amounts for seven other Type 1 and Type 2 resources that were included in the 7(b)(2)(D) resource stack. We will provide a brief discussion of the review that was performed and the results of the review used in answering the IOUs' data requests concerning the costs of resources that are contained in the resource stack.

(1) Dalles Dam Fish Ladder – This 4.6 aMW hydro resource is contracted to meet the regional loads of Puget Sound Energy. We had incorrectly determined that the power output from this resource was being sold to meet loads in California. Based upon the revised determination of the loads that this resource is serving, it should no longer be included in the resource stack to meet the loads in the 7(b)(2) Case.

(2) Boardman Coal Plant –- Power Resources Cooperative's (PRC) 10 percent ownership of the Boardman Coal plant is sold out of region to the City of Turlock, California. The cooperatives' members are all BPA preference customers. The Boardman Coal plant is 65 percent owned by Portland

General Electric and is operated by PGE. We made a data request to PGE, one of the Joint Party members of JP6, for projected operating budgets and other pertinent financial and other operating information concerning the operation of the Boardman coal plant to properly determine the cost of the 10 percent of the resource owned by PRC that should be properly included in the 7(b)(2)(D) resource stack. PGE denied BPA's data request (despite their insistence in JP6 testimony that we obtain and document the best cost data available) and indicated that we should contact Pacific Northwest Generating Cooperative (PNGC) directly, who at the time we believed held the 10 percent interest in the Boardman coal plant. A similar request of PNGC informed us that the interest is owned by PRC and that BPA should contact them for the information. It appears to us that there are over-lapping ownership interests between PRC and PNGC, they share the same business address, and have other common shared attributes of ownership and operation. PNGC is a party to this rate case while PRC is not. Both PGE and PNGC could have been more helpful in providing the necessary information requested, but chose otherwise. We will continue to try to get the financial and operating cost information that is representative of PRC's 10 percent ownership interest to be able to project the costs for this resource for FY 2007-2013. Absent obtaining the requested information, we have relied on PGE's FERC Form No. 1 filing for CY 2004-2006 to project the costs for this resource. This information was included in Response to Data Request No. JP6-BPA-1, which is attached to this testimony. *See* Attachment 6, Subpart 1, Updated Cost Projections for Boardman Coal Plant.

(3) Cowlitz Falls Hydro Project Resource – The output of this resource, owned by Lewis County in Washington state, has been acquired by BPA. It is a Type 1 resource that is properly included in the resource stack. The projected costs for this resource in the resource stack are based on the projected budget amounts for operating and maintenance expense for this project that are included in the Program Case revenue requirements along with the recomputed debt service amounts that include the additional 5 basis point interest rate spread adjustment outlined in the Estimated Financing Costs Study, WP-07-E-BPA-50, Appendix A. A revised cost projection based on more current information was included in Response to Data Request No. JP6-BPA-1. This information is attached to this testimony. *See* Attachment 6, Subpart 2, Updated Cost Projections for Cowlitz Falls Hydro Project.

(4) Idaho Fall Bulb Turbine Hydro Project –- The output of this resource, owned by the City of Idaho Falls, has been acquired by BPA. It is a Type 1 resource that is properly included in the resource stack. The projected costs for this resource are based on the projected amounts for the purchased power contained in the Program Case revenue requirements. A revised cost projection for this resource based on more current information was included in Response to Data Request No. JP6-BPA-1. This information is attached to this testimony. *See* Attachment 6, Subpart 3, Updated Cost Projections for Idaho Fall Bulb Turbine Hydro Project.

(5) Wauna Cogeneration Project –- The output of this resource, owned by the Western Generation Agency, an intergovernmental agency comprised of Clatskanie People's Utility District and Eugene Water and Electric Board, and has been acquired by BPA. It is a Type 1 resource that is properly

included in the resource stack. The projected costs for this resource are based on the projected amounts for the purchased power contained in the Program Case revenue requirements. A revised cost projection for this resource based on more current information was included in Response to Data Request No. JP6-BPA-1. This information is attached to this testimony. *See* Attachment 6, Subpart 4, Updated Cost Projections for Wauna Cogeneration Project.

(6) Nine Canyon Wind Project –- The output of this resource is owned by a group of preference customers as detailed in Attachment 6, Subpart 5 to this testimony. The resource is owned and operated by Energy Northwest. It is a Type 2 resource. The portion of the resource output and the corresponding costs that have been determined to be uncommitted to regional loads have been included in the 7(b)(2)(D) resource stack. Energy Northwest's operating and budget information formed the basis for our cost calculations for this resource. Since the time this information was prepared, we have become aware that the new Phase 3 of this project will become operational around May 2008. This augmented resource would be available to meet loads in FY 2009. We will update the final Supplemental Proposal if this augmented resource information becomes available.

(7) Billing Credit Resources –- This resource combines four small billing credit resources BPA has contracted for: (1) South Fork Tolt Hydro Project, owned and operated by the City of Seattle; (2) Wynochee Hydro Project, owned and operated by the City of Tacoma; (3) Smith Creek Hydro, project owned and operated by the City of Eugene; and (4) Short Mountain Landfill Project, owned and operated by Emerald PUD. These resources are Type 1 Resources. The billing credit resources are grouped together as a composite

resource for ease of modeling in the resource stack. The projected costs for these resources are based on the projected average purchase power costs contained in the Program Case revenue requirements. The projected cost information that was included in Response to Data Request No. JP6-BPA-1 has been attached to this testimony. *See* Attachment 6, Subpart 6, Billing Credit Resource Cost Information.

(8) Mid-Columbia Resources – We have become persuaded through other rate case parties' testimony that a small portion of certain Mid-Columbia resources (Grant PUD's Priest and Wanapum Hydro resources) should have been included in the resource stack. The cost analysis that is currently contained in Appendix C of the Section 7(b)(2) Rate Test Study, WP-07-FS-BPA-06, will be used to cost the Mid-Columbia resources for the FY 2007-2008 Lookback analysis. This Mid-Columbia resource information will be updated and revised for more current operating cost information to project the costs for the FY 2009-2013 rate test period for the FY 2009 rate test.

In undertaking the review of resource stack cost information in responding to the IOUs' data requests, we became aware that the GNP deflator and inflation indices that are used to convert the nominal dollars for the year that costs were actually incurred to the "real" purchasing power dollars in the year that the resource is selected from the resource stack needed to be revised. Revised and more current GNP deflator indices based on information obtained from Global Insight's user website will be incorporated into the rates models for the final Supplemental Proposal. The updated table of GNP deflator and inflation indices is attached to this testimony. *See* Attachment 6,Subpart 8, GNP Deflator and Inflation Indices.

For the final Supplemental Proposal, we will provide an additional appendix that documents the operating and financial cost information for all non-conservation resources (excluding the Mid-Columbia resources, which will be documented in Appendix C), similar to the WP-07 Final Proposal Appendix D that documents resource information for conservation resources.

Q. *The IOUs argue that BPA should provide a full and complete justification for the resources to be included in the 7(b)(2)(D) resource stack and the information regarding those resources to be used in determining the 7(b)(2) Case costs and provide an opportunity for parties to review and respond. LaBolle, et al., WP-07-E-JP6-08 at 9. For example, BPA should demonstrate that (i) any resource included in the 7(b)(2)(D) resource stack for any portion of the Five-Year Period is, in fact, a resource that is projected to be operating (e.g., not obsolete) during the Five-Year Period, and (ii) the costs in the 7(b)(2)(D) resource stack of any such resource are, in fact, the projected costs of such resource. Id. Do you agree?*

A. We agree that we should provide a full and complete justification for the resources to be included in the 7(b)(2)(D) resource stack along with the information used to determine the 7(b)(2) Case resource costs and corresponding energy or conservation savings. We agree that we should demonstrate the propriety of including a resource in the resource stack and that the costs of the resources are correct and accurate cost projections. However, in order to ensure that the development of resource cost information for the 7(b)(2) Case is based on consistent assumptions and cost information that are consistent with the final Supplemental Proposal Program Case, it will be necessary to update the conservation resource information that was formerly based on FY 2005-2007 projections for the actual historical information that will be available in May 2008 as explained in the response above.

In addition, the updated cost projections for conservation expenditures and savings for FY 2008-2013 should be updated to be consistent with the costs and budget assumptions that are in the Program Case for the final Supplemental Proposal. As outlined above, we are planning to update revenue requirements amounts for budget decisions over conservation expenditures, fish and wildlife costs, CGS costs, and other operating costs that will be presented and discussed in the Integrated Program Review process. The determination of BPA's costs and budgets are not decided within the 7(i) rate proceeding.

Q. *The IOUs argue the resources and information in the 7(b)(2)(D) resource stack can have a significant impact on the results of the section 7(b)(2) rate test and the determination of any section 7(b)(2) trigger amount. LaBolle, et al., WP-07-E-JP6-08 at 10. This is particularly the case if substantial resources must be drawn from the stack in the 7(b)(2) Case to meet remaining general requirements of the 7(b)(2) Customers once the available FBS is exhausted. Id. Do you agree?*

A. Yes.

Q. *The IOUs argue BPA should not attempt to develop the necessary 7(b)(2)(D) resource stack information without a detailed methodology that ensures the accuracy and verifiability of that information. LaBolle, et al., WP-07-E-JP6-08 at 10. BPA should adopt such a 7(b)(2)(D) resource stack information methodology and apply it in this and future general rate cases for the identification of resources for the 7(b)(2)(D) resource stack and for development and documentation of data needed for such resources in the performance of the section 7(b)(2) rate test. Id. Do you agree?*

A. In general, we do not agree with this argument. The Implementation Methodology provides sufficient direction as to the three types of resources that are to be included in the resource stack. The proposed Implementation Methodology also provides additional direction and guidance in the methods used to develop the 7(b)(2)(D) resource stack information. If the record for this rate case establishes specific areas where the proposed Implementation Methodology should be improved to include greater detail on the procedures to be used in modeling the 7(b)(2)(D) resource stack costs, then those procedures would be incorporated in the final Implementation Methodology that is adopted within the Final ROD.

As outlined in the above response, we plan to include updated resource energy capabilities and revised cost projections in three updated appendices for the final Supplemental Proposal. One appendix will update the existing Appendix D for conservation resources. The existing Appendix C information will be updated for Mid-Columbia resource power allocations and revised operating costs, and a new appendix will provide documentation for other non-conservation resources. We want to ensure that the resource cost information and the assumptions that are used to develop the information are accurate and transparent.

Q. The IOUs argue that BPA should not include in the 7(b)(2)(D) resource stack for any portion of the Five-Year Period any resource that, in fact, is not projected to be operating (e.g., is projected to be obsolete) during such Five-Year Period. LaBolle, et al., WP-07-E-JP6-08 at 11-12. Do you agree?

A. We agree that all resources contained in the 7(b)(2)(D) resource stack must be available and capable of meeting the 7(b)(2) Customer loads in any year of the rate test period.

Q. The IOUs argue BPA should include, as costs of resources in the 7(b)(2)(D) resource stack, the projected costs of such resource at cost levels projected to prevail for that resource during the Five-Year Period. LaBolle, et al., WP-07-E-JP6-08 at 12. Do you agree?

A. We agree that the projected resource costs be developed in a manner consistent with the proposed Implementation Methodology. However, there are a number of IOU arguments on how the resource costs should be developed with which we do not agree.

Q. The IOUs argue that BPA should not assume that a resource is available in a given year just because such resource may have been available historically, and BPA should not assume that a resource that was available historically was somehow "stockpiled" without storage, maintenance or carrying costs and is available for FY 2009 in the 7(b)(2)(D) resource stack. LaBolle, et al., WP-07-E-JP6-08 at 12. Do you agree?

A. We do not agree with this characterization of how we developed or how we might choose to develop the 7(b)(2)(D) resource stack. The IOUs' argument implies that resources present in the resource stack are not fully functioning and operating resources in the region, and that there is some doubt as to whether they should have been included in the resource stack. As outlined above, the resource stack for the start of the FY 2002-2008 Lookback period contained a total of 30 resources. All of these resources were currently operating resources within the region. All of the resources, with the exception of The Dalles Dam Fish Ladder, were properly included in the resource stack. The Dalles Dam Fish Ladder was an inadvertent error that has been corrected. We do not believe that there are any "stockpiled" resources in the resource stack.

Q. The IOUs argue that adjusting historical costs for general rates of inflation (e.g., by using a GNP deflator) does not account for these types of costs and does not justify an arbitrary and unrealistic stockpiling assumption. LaBolle, et al., WP-07-E-JP6-08 at 12. Adjusting historical costs for general rates of inflation (e.g., by using a GNP deflator) does not account for these types of costs and does not justify an arbitrary and unrealistic stockpiling assumption. Id. Simply adjusting historical costs by a general rate of inflation does not properly account for changes in prices (and availability) of materials and fuel. Id. Do you agree?

A. We do not agree with the IOUs' argument in total. Type 1 and Type 2 resources contained in the resource stack are resources that exist and have already been built, or planned resources that are expected to be built and acquired by BPA. Thus, it is not necessary to revise the historical costs associated with these resources using a "replacement value" approach in developing the resource costs contained in the resource stack. We believe that the current modeling approach of reflecting the actual historical construction costs for these resources adjusted for changes in general price levels is correct. In the case of Type 1 resources, our current practice of using the actual financing costs adjusted for refinancing savings is correct. This practice is also correct for Type 2 resources that have already been built where the financing is already in place. Our current practice of relying on the operating costs reflected in current financial reports, FERC Form No. 1 information, or the projected operating budgets by the resource owner/operator to project the costs that will be incurred during the rate test period provides a reasonable approximation of the costs that will be incurred during the rate test period. It is reasonable to assume that if we are able to obtain the operating budgets for the Boardman Coal plant from PGE or from PRC for the 10 percent share sold outside of the region, they would contain projected coal fuel costs that would be representative of the projected costs to be incurred during the rate test period.

Q. *The IOUs argue that BPA should not assume for purposes of the 7(b)(2)(D) resource stack that a resource with a given life can be acquired for a shorter period at a cost based on its full life. LaBolle, et al., WP-07-E-JP6-08 at 13. For example, there is no basis to assume that a resource with a 20-year life can be acquired for 5 years at a cost based on the 20-year life of the resource. Id. Do you agree?*

A. We strongly disagree with this statement. The import of this statement would imply that the entire costs of building or constructing resources contained in the 7(b)(2)(D) resource stack that have useful lives of 20 to 30 years would have to be recovered during the shorter rate test period. The current practice of assuming that these resources already exist and that the Joint Operating Agency would be able to purchase the output of the resource for the limited rate test period duration is reasonable. There are numerous examples in the real world where utilities contract for purchase power from independent power producers where the purchase power costs do not reflect a pricing structure that recoups the capital costs associated with resources that have useful lives of 25-35 years to be recovered over shorter purchase power contact time periods.

Q. *The IOUs argue that administrative and general costs allocable to a resource in the 7(b)(2)(D) resource stack should be included in the resource costs reflected in the 7(b)(2)(D) resource stack. LaBolle, et al., WP--07--E--JP6--08 at 13. Do you agree?*

A. We generally agree with this statement to the extent it is consistent with BPA's current practice. Conservation resources in the resource stack contain an allocation of general and administrative (G&A) costs for the vintage year in which BPA acquired the conservation savings. We assume that the costs of other resources in the resource stack contain an allocation of G&A costs from the resource provider and are included in the costs contained within power purchase contract terms or in the operating cost budgets for Type 2 resources. In addition, the 7(b)(2) Case revenue requirement contains BPA's total G&A costs that reflect the same G&A costs contained in Program Case revenue requirement, with the exception of G&A costs and other overhead charges associated with BPA's Energy Efficiency operations. BPA assumes that the costs that are contained in the 7(b)(2) Case revenue requirement, together with the costs of the added resources from the stack, correctly represent the total 7(b)(2) Case costs, including all applicable G&A costs.

Q. The IOUs argue that the costs shown for a number of the resources included in the 7(b)(2)(D) resource stack include no capital costs. LaBolle, et al., WP-07-E-JP6-08 at 13. These resources include The Dalles Dam Fishway, Boardman, Idaho Falls, and Nine Canyon Wind project. Id. The IOUs argue the costs of a generating resource necessarily include its capital costs, and it is unrealistic to assume that BPA could acquire these resources without paying an annual capital cost component. Id. Please respond.

A. The IOUs' assertions are incorrect. However, the IOUs did not have the benefit of having received our responses to their data requests when they drafted their testimony. We will address each of the IOUs' assertions regarding the cited resources.

(1) Because <u>The Dalles Dam Fishway</u> will be excluded from the resource stack, it is not necessary to rebut the argument for this resource.

(2) <u>Boardman Coal Plant</u> – As documented in Attachment 6, Subpart 1, Updated Cost Projections for Boardman Coal Plant, BPA has included a

10 percent debt service component that reflects 100 percent financing for this ownership interest portion that incorporates the estimated financing costs (interest rate) associated with the financing cost study based on historical information present in PGE's FERC Form No. 1 for prior years. As outlined in the above responses, we hope to be able to update the cost projections for this resource if information requested from PGE or PNGC/PRC becomes available to inform BPA's cost projections for the final Supplemental Proposal.

(3) Idaho Falls Bulb Turbine Hydro Project – As documented in Attachment 6, Subpart 3, Updated Cost Projections for Idaho Falls Bulb Turbine Hydro Project, this resource is modeled after the power purchase contract that is present in the Program Case. It is reasonable to assume that the City of Idaho Falls included the recovery of its capital costs for the project when it contracted for the sale of the output of this project to BPA. Due to the nature of the terms for this power purchase contract there is no need to include a capital cost component.

(4) Nine Canyon Wind Project – As documented in Attachment 6, Subpart 5, Updated Cost Projections for Nine Canyon Wind Project, the operating cost information for this project is based on Energy Northwest's operating budgets for this project. Because the resource is already built and financed, the existing debt service remains in place as BPA had no involvement with the financing of this resource. The annual operating budget projections contain annual debt service costs that cover the capitalized costs of construction. All of the costs of this project including debt service for capital costs were included in the annual operating and maintenance costs for this project.

Q. The IOUs argue that for the Nine Canyon wind resource, the Supplemental Proposal does not appear to include the costs for within-hour balancing in the 7(b)(2) Case costs when that resource is drawn from the 7(b)(2)(D) resource stack. LaBolle, et al., WP-07-E-JP6-08 at 14. The within-hour balancing costs need to be included to provide an accurate assessment of the resource's cost. Id. Moreover, BPA has indicated in another proceeding that its unit cost for within-hour balancing may increase in the fixture, as the wind penetration level increases. Id. Do you agree?

A. We relied on the projected operating costs for this resource as contained in the project owner/operator's (Energy Northwest) projected operating budgets. There is not a specific line item that is designated within-hour balancing costs or resource firming costs. There is a separate line item for transmission costs. We are following up on the IOUs' concerns that the operating costs for this project would be understated unless within-hour balancing costs or resource firming costs were included in the operating cost projections for this project with Energy Northwest. The operating costs for this resource will be updated for the final Supplemental Proposal and this issue will be addressed in documenting the operating costs for this resource. This information will be presented in a new appendix documenting non-conservation costs as outlined in the answers above.

Q. Cowlitz/Clark argue that BPA uses a different cost for the conservation resources it has acquired (or expects to acquire) in the 7(b)(2) Case than the actual cost BPA incurs for such conservation. Schoenbeck and Beck, WP-07-E-JP17-01 at 18. Cowlitz/Clark cite a table providing examples of the different costs of the conservation resource calculated as a "first year input" cost to the first year cost used from the least cost stack selection process from BPA's FY 2002-2006 RAM.

Comparison of First Year Conservation Costs

(Dollar Amount in $1,000)

Program Year	Calculated Cost	Year Needed	7(b)2 Stack Cost	Difference
2007	$88,258	2010	$119,618	$31,360
2008	$87,669	2010	$116,460	$28,791
2009	$87,470	2009	$109,955	$22,486
2010	$87,409	2010	$111,093	$23,685

The "Calculated Cost" column is intended to replicate what the first year cost of acquiring the section 7(b)(2) conservation stack amount would be in the Program Case. Id. That is, the revenue-financed portion is included in the first year plus an amortization component based upon a 15-year life for the capitalized portion. Note that for "Program Years" FY 2009 and FY 2010, the 7(b)(2) Case least cost logic selected the conservation resource in the same years, i.e. FY 2009 and FY 2010, respectively ("Year Needed"), but the cost in the 7(b)(2) Case was over $22 million higher. Id. Further, for Program years FY 2007 and PY 2008, the 7(b)(2) Case stack cost is substantially greater than what would have resulted from a modest two or three years of inflation. Id. These costing differences should be eliminated. Id. But for any modest "financing benefits" that section 7(b)(2) says should not exist in the 7(b)(2) Case, the cost of identical resources should be the same in both cases. Id. Do you agree?

A. As outlined above in our response to the IOUs, we now realize that there were problems with the deflator indices used to restate the actual nominal costs of conservation investments in the years that they were incurred to costs reflected in real 1980 dollars. A revised set of GDP deflator–inflator indices presented on Attachment 6, Subpart 8 was used to revise the statement of conservation costs in the tables presented at Attachment 6, Subpart 7 that presents the conservation costs in the actual nominal dollars of the year incurred, and in real 1980 and 2007 dollars. In addition to using these restated dollar values for conservation investments stated in 1980 dollars, we will also revise the inflator values in the model used to escalate the conservation investments stated in 1980 dollars to the purchasing power dollars for the year that the conservation investment is selected. These changes will address these problems in all versions of the rate models.

Q. Cowlitz/Clark argue that BPA's simplistic least cost selection logic introduces additional problems with regard to conservation that can best be termed "Beginning Effects." Schoenbeck and Beck, WP-07-E-JP17-01 at 19. BPA determines the least cost order based upon a levelized life-of-the-resource calculation over periods of 20 to 35 years in 1980 dollars. Id. But for purposes of determining the 7(b)(2) Case nominal dollar resource addition cost, the model "mimics" BPA's front loaded revenue financing approach to conservation in the first year. Id. In subsequent years, BPA reflects only the interest cost and remaining capitalized amortization cost. Id. As the 7(b)(2) Case resource selection can be as short as just one year, conservation is assumed in the 7(b)(2) Case to be acquired at an incredibly high cost. Id This "Beginning Effect" problem results in a resource cost that is far too high compared to real world alternatives and is not a least cost selection process. Id. BPA's modeling of conservation simply creates another penalty to preference customers in the 7(b)(2) Case. Id. Do you agree?

A. The method of costing of conservation resources in the 7(b)(2) resource stack has remained unchanged for over twenty years. In addition, relatively high first year costs are not unique to the 7(b)(2) Case. Indeed, because actual programmatic conservation carried out in the Program Case may be as much as 70 percent expensed in the first year and have a useful life of up to 20 years, the first year costs per megawatt-hour of savings can be in the range cited by Cowlitz/Clark. In our direct testimony, however, we left open the possibility of changing the costing methodology for conservation resources in the 7(b)(2) resource stack.

Q. Do you propose any change to the assumptions used regarding the capitalization and financing of conservation in the Program Case?

A. Yes. We recognize that whereas annual programmatic conservation comes on one annual program at a time each year in the Program Case, in the 7(b)(2) Case several of these same annual programmatic conservation resources can be brought on in a single year. As a consequence of BPA's annual programmatic conservation being in the 7(b)(2) Case resource stack, some financing assumption other than the actual historical practice may be reasonable in the 7(b)(2) Case. We have outlined an alternative approach to financing the first year expensed conservation amounts later in our testimony.

Q. Cowlitz/Clark argue that for FY 2010, four conservation blocks are selected representing BPA's conservation programs from the years 1993, 2007, 2008 and 2010. Schoenbeck and Beck, WP-07-E-JP17-01 at 20-21. If BPA does not eliminate conservation from the resource stack, it should at least limit the amount of conservation that can be acquired to no more than a single block each year as has historically been achieved. Id. Do you agree?

A. No. To the extent that Cowlitz/Clark perceives a costing problem with conservation resources in the 7(b)(2) resource stack, the solution is not to limit the number of conservation resources brought on in a given year. Because the 7(b)(2) Case PF load is increased by all foregone conservation, limiting the number of conservation resources allowed to be brought on in a given year may make a load/resource balance in that year more expensive by first using other available, higher cost resources, and then using Type 3 resources. Cowlitz/Clark have pointed out how the current financing of conservation in the 7(b)(2) resource stack can lead to something other than the least-cost first acquisition of resources from the stack required by section 7(b)(2)(D). One possible solution to this perceived problem is to capital finance the entire cost of conservation resources. Although this would bring the first year cost of a conservation resource in line with that resource's levelized cost of power that is used to sort the resources by least cost first, it ignores the fact that these first year costs are costs that were properly expensed in the year incurred. Another possible solution is to spread the first year expensed portion over a set number of years as described in this testimony. Any change from the current treatment of conservation costs will be made considering the full ratemaking record.

Q. Cowlitz/Clark argue that, taken together, modeling deficiencies inappropriately bias the 7(b)(2) result to reduce substantially the protection 7(b)(2) was to provide preference customers. Schoenbeck and Beck, WP-07-E-JP17-01 at 21. Cowlitz/Clark argues that to prevent these perverse results, BPA should neither inflate the preference general requirements nor treat conservation as if it were a 7(b)(2)(D) resource in the 7(b)(2) Case. Id. Do you agree?

A. No. As stated above, the Implementation Methodology is clear that conservation is a 7(b)(2)(D) resource and, as such, the 7(b)(2) PF load forecast must be adjusted for the foregone conservation. However, there may be modeling and accounting changes that can be adopted that would make the acquisition of conservation resources from the stack comport better with industry practice of capitalizing and deferring costs to the rates collected in subsequent years to address Cowlitz/Clark's "rate-shock" concerns. This alternative may partially address the least cost resource selection concerns associated with high expense levels associated with the first year that a resource is selected from the resource stack.

Q. Cowlitz/Clark argue that BPA uses different "new resources" costs in the Program Case and the 7(b)(2) Case. Schoenbeck and Beck, WP-07-E-JP17-01 at 24. In the Program Case, the cost of each "new resource" has been derived from the specific contractual provisions or expected cost for each year for that resource. Id. Each new resource is a purchased power contract that obligates BPA to pay a defined amount for the output of generation facilities owned by other parties. Id. The amount BPA pays is generally designed to reimburse the facility owner for fixed costs (mostly interest on and amortization of the capital cost of the facility) and the variable costs of operating the facility. Id. In the 7(b)(2) Case, a resource is chosen from a "least cost resource stack" which uses as a starting point the cost of resources stated in 1980 dollars. Id. As a resource is selected from the stack, the 1980 value is escalated to a nominal dollar value as of the year in which the resource is first needed to meet the general requirements in the 7(b)(2) Case using a single escalation vector for all resources. Id. Do you agree?

A. Yes.

Q. Cowlitz/Clark argue that only if the actual pricing provisions in BPA's various purchased power contracts precisely match the BPA escalation approach, a highly unlikely event, will BPA's escalation method produce the same cost of the resource in both the Program Case and the 7(b)(2) Case. Schoenbeck and Beck, WP-07-E-JP17-01 at 24. It is very unlikely that this method will replicate BPA's actual cost of the resources because BPA's 7(b)(2) method has the effect of escalating the fixed capital cost from the date of actual commercial operation to a later date. Id. But fixed capital costs are fixed; they do not escalate after they are incurred. Id. Thus, the component of BPA's purchased power contracts designed to cover fixed cost of resources in the 7(b)(2) Case are higher than BPA *actually must pay for them. Id. In short, BPA inappropriately uses higher costs for the resources in the 7(b)(2) Case than for the same resources in the Program Case. Id. Do you agree?*

A. We agree that fixed costs, once inflated to the year of selection, should be fixed from that time forward and that the related debt service amounts to finance fixed capital costs should also remain fixed for all subsequent years of the rate test period. The rate model used to revise rates for FY 2009 has corrected this problem that is still present in the FY 2002-2006 Lookback model and the FY 2007-2008 Lookback Model. BPA will consider making the changes concerning the treatment of fixed cost in the FY 2002-2008 Lookback rate models.

Q. Cowlitz/Clark argue that the "cleanest" example is the Idaho Falls resource BPA acquired since there is no financing benefit associated with this project. Schoenbeck and Beck, WP-07-E-JP17-01 at 25. Cowlitz/Clark argue that while the Program Case cost of the resource is essentially flat at $22/MWh, in the 7(b)(2) Case BPA's modeling approach results in the resource costing from $36 to $47/MWh over the 7(b)(2) period. Id. BPA's FY 2002- 2006 RAM does not select this resource until FY 2009 when it has been assigned a nominal cost of almost $46/MWh, or over twice its actual cost in the real world and the Program Case. Id. Do you agree?

A. As outlined in our response above, we acknowledge that the Supplemental Proposal models had incorrect GNP deflator/inflator values. We will correct the GNP deflator/inflator values contained in the rate models for the final Supplemental Proposal to comport with the GNP deflator/inflator values that are presented in Attachment 6, Subpart 8.

Q. Cowlitz/Clark argue that BPA should assign costs to resources in the 7(b)(2) Case by assigning actual costs to actual resources, just as happens in the

Program Case. Schoenbeck and Beck, WP-07-E-JP17-01 at 25. The cost of resources not needed to meet general requirements in the 7(b)(2) Case should be allocated to other sales, such as FPS sales. Id. Do you agree?

A. We do not agree with this approach, which is contrary to section 7(b)(2) and the proposed Implementation Methodology. Section 7(b)(2)(D) contemplated that there could be a different mix of resources serving the different loads that are present in the two cases. The least cost selection process results in a different mix of resources serving the two Cases, and some resources might serve the loads in the 7(b)(2) Case in later time periods than what occur in the Program Case. Thus the "actual costs" will be different between the two Cases for these reasons. The only FPS sales that the Implementation Methodology instructs us to serve are those represented by contracts that were effective before December 5, 1980, and they are to be served with FBS resources. In the 7(b)(2) Case, the Cowlitz/Clark proposal would result in resources being acquired to serve loads in excess of the 7(b)(2) Customer loads. In addition, as we outline in our response to the PPC and the IOUs elsewhere in this testimony, the development of the costs for the two Cases are different. The Implementation Methodology instructs that they are different by the Five Assumptions.

Section 8: Estimated Financing Costs

Q. PPC defines the opposite of "financing benefits" as a "financing penalty": a higher interest rate that a joint operating agency (JOA) of consumer-owned utilities would have to pay to borrow money in the absence of BPA participation in the resource. O'Meara, et al., WP-07-E-PP-9 at 21. Do you agree?

A. Section III of the 1984 Section 7(b)(2) Implementation Methodology is entitled "Financing Benefits." It deals with interest assumptions surrounding the rates of borrowing for capital costs in the resource stack. Section III provides "the 7(b)(2) customers' power costs may be higher by some amount in the 7(b)(2) case because the customers themselves would have to finance the acquisition of additional resources needed to meet their firm loads after BPA's FBS resources are exhausted."

BPA's current and prior financing studies outline the cost of financing the three different types of resources outlined in section 7(b)(2)(D) of the Northwest Power Act. All of these financing studies have consistently indicated that the financing cost for Type 3 resources, resources acquired from non-7(b)(2) customers, would be less expensive in the 7(b)(2) Case when compared to the Program Case. Thus, the financing difference for these resources is positive (less expensive in the 7(b)(2) Case). Although these resources are not needed during the current FY 2002-2008 Lookback and FY 2009 Supplemental Proposal, they might be needed in future rate cases. In general, the cost of financing for Type 1 and 2 resources is less expensive in the Program Case than the financing cost used in the 7(b)(2) Case. The rate test quantifies the differences in the cost of financing between the two cases. BPA does not describe this with the pejorative term "penalty." Instead, BPA quantifies the difference in the financing costs between the two Cases with either the generic term "financing benefits" or "estimated financing costs." These terms are more neutral in their description because, in the case of Type 3 resources, the financing studies have indicated that the financing benefit in the 7(b)(2) Case is positive.

Q. PPC argues that in the 7(b)(2) Case, BPA assumes that utilities develop resources, mainly conservation, without BPA's participation or "backing." O'Meara, et al., WP-07-E-PP-9 at 21. This means that utilities would have to raise funds in capital markets on their own. Id. The question then arises, what *interest rate "penalty" (financing penalty) will those utilities face, compared with the Program Case? Id. Please respond.*

A. As outlined above, the Implementation Methodology instructs us to quantify the differences in financing costs between the Program Case, with BPA's participation or backing, and the 7(b)(2) Case, where the financing is undertaken without BPA's participation or backing. As outlined in the preceding response, we find the term "penalty" to be pejorative and incorrect regarding the financing costs associated with Type 3 resources. The current and prior financing studies have all concluded that a reasonable assumption for the most favorable "financing vehicle" to accomplish this financing in the 7(b)(2) Case would be the formation of a Joint Operating Agency (JOA) (similar to Energy Northwest), which would generally enjoy a lower risk profile and a better credit rating in the aggregate, as opposed to each COU issuing its own bonds separately. The assumed use of a JOA also simplifies the needed analysis because it would be very difficult to calculate different financing costs for each and every potential financing entity that would borrow funds for the various uses considered in the 7(b)(2) Case.

Q. PPC argues that BPA's large difference between Named and Generic resources does not seem reasonable. O'Meara, et al., WP-07-E-PP-9 at 22. PPC reviewed the PFM Group report to see if it pointed to any specific market conditions or assumptions that would create such a difference in financing penalties (benefits) between actual and generic resources. Id. PFM states that it took into account the fact that Lewis County PUD could use the Cowlitz Falls resource to meet its own load obligations. Id. However, PFM does not state that this observation led to the specific basis point differential. Id. Please respond.

A. There are two "named resources" in the 7(b)(2) resource stack: Idaho Falls, owned by the City of Idaho Falls, and Cowlitz Falls, owned by Lewis County

PUD. On page 8A of the financing study report, PFM states that the financing for these two projects is assumed to have occurred at the time when the revenue bonds were issued to provide financing for the capital costs of each respective resource. This treatment of these two resources by PFM was also identical to the treatment used by the four previous financial advisors who prepared prior Estimated Financing Cost Reports. PFM states that in the case of the Idaho Falls Project, because the revenues of the City's Electric System secure the revenue bonds, the existence of the BPA Power Purchase Agreement is not material to the credit rating of the bonds. Based on the PFM Financing Report, no financing adjustment for this resource was made in the 7(b)(2) Case.

In the case of the Cowlitz Falls resource, PFM stated that the contract and payment provisions requiring BPA to pay all project costs, including debt service, directly to the bond trustee, provides the primary support for the current credit ratings associated with the bonds issued. PFM stated that BPA retains the "dry hole risk" and is obligated to pay the debt service for the full term of the bonds whether the project is operating or not. PFM's financing report, while acknowledging the fact that Lewis County PUD could use the Cowlitz Falls resource to meet its own load obligations, did not find this fact as important as the contract and payment provisions that require BPA to pay debt service for the life of the bonds to the bond trustee in addressing the financing cost difference in the 7(b)(2) Case. PFM concluded that the cost of financing in the 7(b)(2) Case was 5 basis points higher than the financing cost attributable to the Program Case. This financing cost differential was factored into the cost of this resource in the resource stack.

The difference in the financing costs between "Named Resources," which adopt the financing costs for the project at the time when the revenue bonds were issued or refinanced to provide for the capital costs of the named resource, is consistent with the cost development of the purchase power contracts present in the Program Case. In order to achieve cost comparability between the two Cases, the financing costs of named resources require one to use the financing costs at the time the bonds are issued or refinanced. Financing resource costs for generic resources, on the other hand, use the projected financing costs of the rate test period. The fact that named resource financing costs are different than generic resource financing costs is not consequential to the rate test. Section 7(b)(2)(E) of the Northwest Power Act directs BPA in performing the rate test to quantify the differences between a resource's financing cost in the Program Case versus the 7(b)(2) Case. For some resources it is appropriate to let the historical financing costs "stand" in the Program Case and quantify the financing cost difference attributable to not having BPA backing in the 7(b)(2) Case. This is the case for named resources and it is also the case for Type 2 resources (resources owned by 7(b)(2) Customers that are not dedicated to regional loads pursuant to section 5(b) of the Act). Because these resources are already constructed and financed, a financing cost analysis is not required. *See* 1984 Section 7(b)(2) Implementation Methodology at 12, Note 8. Section 7(b)(2)(E) does not require that the financing costs between named resources and generic resources be comparable. In fact, the opposite is true. In order to ensure that the financing cost differences between the two Cases for named resources are correct or reasonable, the historical financing costs that are in place have to be used. In the case of generic resources, the financing cost differences are associated with the projected financing costs over the rate period. The historical "in place" financing costs associated with named resources are not comparable with the projected financing costs of generic resources over the rate test period.

Q. PPC states that BPA says "[f]or the purposes of the 7(b)(2) test, Lewis County PUD is assumed to accept the 'dry hole risk' and that [sic] the Cowlitz Falls Project output would be dedicated to serving Lewis County PUD's own load." O'Meara, et al., WP-07-E-PP-9 at 22. This means that a single utility would be taking on the "dry hole" risk, which is an important difference in the 7(b)(2) Case. Id. Also, the financing benefit for the uninsured Cowlitz Falls revenue bonds was estimated by calculating the cost of insuring the bonds. Id. This resulted in the five basis point financing benefit. Id. Do you agree?

A. No. The five basis point financing benefit in the Program Case is not due to the purchase of bond insurance. The implicit cost of purchasing triple AAA-rated insurance policies was taken into account and removed to arrive at the true interest cost of 4.20% in the Program Case. Similarly, the cost of purchasing AAA-rated bond insurance was also taken into account and removed in determining the true interest cost of 4.25% used in the 7(b)(2) Case.

Q. PPC states that the PFM Group, with regard to financing benefits for generic resources, rather than applying the bond insurance methodology described above, in essence assumes the financing benefits to be equal to the interest rate differential associated with the difference between A and AA ratings. O'Meara, et al., WP-07-E-PP-9 at 23. PFM does not explicitly state that the JOA in the 7(b)(2) Case would have an A rating, or that BPA Backing would raise the borrower's bond rating from A to AA in the Program Case, however, these are the apparent assumptions. Id. Do you agree?

A. No. At page 6A of its estimated financing cost report, PFM states the assumption of using "A" and "AA" credit ratings for generic resources. "Based on such a typical financing structure (use of the JOA), and in concurrence with the assumptions contained in prior 7(b)(2) Financing Cost Studies, we have assumed that a financing by a JOA consisting of the assumed member agencies (as outlined on Attachment A) would have received and been able to maintain a rating in the "A" category from both Moody's and S&P – two well regarded bond rating agencies. In the case of the JOA or 7(b)(2) Customer issuing revenue bonds with the advantage of a BPA "take-or-pay" or "capability" power sales contract, we have assumed the financing would have received and maintained a rating in the "Aa/AA" from both Moody's and S&P." See the revised Attachment A to PFM's Estimated Financing Costs study at Attachment 7.

Q. *PPC argues that PFM uses two different methodologies to derive financing benefits for the Cowlitz Falls and JOA resources, but does not explain why each methodology is appropriate to its own situation. O'Meara, et al., WP-07-E-PP-9 at 23. Second, PFM does not explain why a JOA consisting of 117 utilities would have an "A" bond rating. Id. Third, PFM does not explain why BPA Backing would effectively raise that bond rating to "AA". Id. PPC claims there is no evidence one way or the other on this subject in the PFM report. Id. Do you agree?*

A. No. As outlined in the prior response, it is necessary to treat "named resources" differently because the cost contained in the Program Case for the power purchase contracts reflects the cost of financing at the time the funds were needed to finance the capital costs of construction. The cost of financing generic resources such as conservation or Type 3 resources have either different cost treatment in the Program Case, as in the case of conservation resources, or they do not exist in the Program Case, as in the case of Type 3 resources. Thus, the financing cost assumptions for generic resources use the forecasted financing costs to determine the financing cost spread between the two Cases. The difference in the financing costs that apply to "named resources" and generic resources was adequately explained in PFM's financing study.

PPC's second claim is that PFM does not explain why a JOA consisting of 117 utilities would have an "A" bond rating. The assumption outlined above ("Based on such a typical financing structure (use of the JOA), and in concurrence with the assumptions contained in prior 7(b)(2) Financing Cost Studies, we have assumed that a financing by a JOA consisting of the assumed member agencies would have received and been able to maintain a rating in the "A" category from both Moody's and S&P – two well regarded bond rating agencies.") was not documented in the financing report. However, the "A" rating is a reasonable rating for the JOA comprised of the COUs that are outlined at Attachment A of the financing study. BPA compared the most recent credit ratings available for these COUs from Standard and Poor's (S&P), Moody's, and Fitch. Averaging the three ratings from these entities, of the total generators (PUD No. 1 of Lewis County was reclassified as a generator), 36 percent of the JOA ownership (consisting of generating member entities reflected on Attachment A) have a current average credit rating of "A," and 18 percent of the generating members have a current average credit rating of "AA." Non-generators with greater than a 1 percent share, totaling 11 percent of the ownership of the JOA, had a current average credit rating of "A." Remaining non-generator members of the JOA with less than a 1% interest in the JOA, totaling 35 percent, were not taken into account. In summary, the current average credit rating attributable to 47 percent of the members making up the hypothetical JOA is "A" and 18 percent of the members have a current average credit rating of "AA." Thus, the assumption that the JOA financing without BPA backing would receive an "A" credit rating is reasonable.

PPC's third claim is that PFM does not explain why BPA Backing would effectively raise that bond rating to "AA." Recent financings of the JOA Energy Northwest that have BPA backing have received ratings of "AA-" from S&P and Fitch and "Aaa" from Moody's (bonds were issued without bond insurance). Thus, the financing report's assumption ("In the case of the JOA or 7(b)(2) Customer issuing revenue bonds with the advantage of a BPA "take-or-pay" or "capability" power sales contract, we have assumed the financing would have received and maintained a rating in the "Aa/AA" from both Moody's and S&P.") is also reasonable based on recent BPA-backed Energy Northwest financings.

Q. *PPC argues that BPA's responses to data requests provided no additional information, but simply referred PPC to the Appendix to the Final Study cited above (but referenced variously as the report by Sutro & Co., Incorporated and the PFM Report). O'Meara, et al., WP-07-E-PP-9 at 23. Do you agree?*

A. No. In PPC Data Requests PP-BPA-33, -34, -35, and -36, we did not simply give a response that referred to the two financing study documents. Our response to these data requests provided additional explanations for the material contained in the financing studies. The responses were thorough and addressed the questions and topics contained in the data requests.

Q. *PPC states that PFM's conclusions regarding generic resources purchased from the JOA in the 7(b)(2) Case should be rejected. O'Meara, et al., WP-07-E-PP-9 at 24. PPC argues PFM could have reasoned that the JOA would have issued insured bonds in the absence of BPA Backing, and that the most recent evidence of the cost of such insurance is five basis points. Id. PPC claims that instead, PFM changed methodologies in mid-report, without explanation. Id. PPC concludes that the best available evidence on this subject is the most recent refinancing (refunding) of the Lewis County bonds, which provides objective* *evidence of what the market for insuring such bonds did in fact charge for such a service: five basis points. Id. Do you agree?*

A. No. As outlined in the response above, if the bonds were insured, one would have to take into account the price of such insurance in arriving at the "true" interest cost differential between the two Cases. To be comparable, the use or non-use of bond insurance would have to be the same in both Cases. Because the cost of bond insurance has to be taken into account to arrive at the true interest rate, it would be an unnecessary complication in the case of generic resources to speculate on the cost of the bond insurance, as well as the difference in the cost of credit with or without BPA backing, to arrive at the true financing cost difference. In addition, a significant factor since the fall of 2007 in the increase in the true cost spread among credit ratings has been changes attributable to the cost of bond insurance. Bond insurance is not as widely available as it was before the fall of 2007 and it is currently more expensive. The change in bond insurance has increased the true cost spread between credit ratings in the current period (January-March 2008). The cost of bond insurance in today's bond market would cost considerably more than five basis points. In responding to the testimony of the Oregon Public Utility Commission concerning interest rate spreads between the two Cases, we indicated that BPA and PFM will evaluate the need to update the financing study prior to preparing the final Supplemental Proposal in response to their concern that the interest rate spread between the two Cases should be greater. If the decision is made to update the financing study, the study would continue to rely on historical averages of the difference in credit spreads with more weight given to recent bond issuances.

As outlined in the foregoing discussion, PFM did not change methodologies in the middle of its report without explanation. As BPA has explained, it is necessary to leave the actual financing cost in place in the case of "named resources" in the Program Case because the original/refinanced cost of debt is implicit in the power purchase contract costs contained in the Program Case. There is a fundamental difference in determining the financing spreads between named resources and the other resources in the resource stack to arrive at the financing cost differential on a resource by resource basis consistent with the Implementation Methodology. The treatment of determining the interest rate spread for named resources and for generic resources used by PFM was the same treatment that was used by the four previous financial advisors in preparing the financing costs estimates for the 7(b)(2) Case. The five basis point spread based on the historical refinancing that took place for the Cowlitz Falls project in June of 2003 is not comparable to the projected financing spreads that will occur over the rate test period for generic resources.

Q. *PPC argues that other evidence PFM provides supports PPC's conclusions. O'Meara, et al., WP-07-E-PP-9 at 24. First, PFM states that the risks of non-completion or technical difficulties are not assumed to be factors that would impact the financing costs of particular resources, that is, there should be no financing penalty or benefit due to these sources of risk. Id. Second, BPA's authority to acquire resources is the same in both the Program Case and the 7(b)(2) Case. Id. As PFM states, "[i] In the Program Case, BPA would contract to purchase power output [based on project financing]. In the 7(b)(2) Case, BPA would contract with the JOA." Id. PPC argues the lack of specific risks and the identity in BPA's acquisition authority point to strong similarities between the Program Case and the 7(b)(2) Case, further reinforcing the conclusion that five basis points is the correct financing benefit. Id. Do you agree?*

A. No, for the reasons outlined in the previous responses.

Q. PPC argues that the lack of effect on the rate test in this particular proceeding does not make this a moot issue because the fact that the effect was not large enough to influence the rate test as modeled by BPA in its Supplemental Proposal does not mean that it would not change the outcome if other changes were made to inputs in the 7(b)(2) Case in this proceeding. O'Meara, et al., WP-07-E-PP-9 at 25. PPC states that, additionally, BPA has a responsibility to properly quantify any monetary savings resulting from BPA financial backing of section 7(b)(2)(D) resources, and should therefore make this change. Id. Do you agree?

A. We agree that we have the responsibility to correctly quantify the financing cost differences between the Program Case and the 7(b)(2) Case between the three different resource types outlined by section 7(b)(2)(D), consistent with section 7(b)(2)(E). We believe that our treatment of the cost differentials in the Supplemental Proposal was correct as of that time. We do not agree with PPC's proposed changes for quantifying the financing cost differences between the Program Case and the 7(b)(2) Case for the different resources present in the resource stack.

Q. The OPUC identifies concerns regarding BPA's estimate of the financing benefits associated with BPA's participation in resource acquisitions of BPA-sponsored conservation and generation resources by publicly owned utilities. Hellman and McGovern, WP-07-E-PU-1 at 28. OPUC argues BPA's approach underestimates the financing benefits because it does not adequately account for, or provide sufficient consideration (weight) to, the increased spreads currently present in today's financial markets. Id. The study BPA relies upon compares JOA borrowing costs to BPA-backed financing and assumes a single rating category difference between the two types of borrowing. Id. Specifically, BPA assumes an AA credit rating for BPA-backed financing and an A credit rating for JOA *borrowing. Id. BPA then makes the assumption that the difference in the rates for A- and AA-rated debt for FY 2009-2013 will be best represented by the period FY 1998-2007. Id. However, since September 2007, spreads (i.e., the difference between actual borrowing costs and Treasury Rates) have increased considerably. Id. How do you respond?*

A. It is evident that credit markets have been in disarray since the fall of 2007. In the latter part of 2007, these developments began to affect credit spread relationships that are central to the financing cost study. Credit spread relationships have continued to deteriorate since the time the financing analysis was completed. It is also evident that experts in the credit markets have not yet developed a consensus on whether the spread among credit ratings will continue to increase, or whether the current spread will decrease in the near future before finding stability at a new equilibrium point. A significant factor in the current increase in the true cost spread among credit ratings has been the changes that have occurred in bond insurance. Bond insurance is not as widely available as it was before the fall of 2007 and it is more expensive. The change in bond insurance cost and availability has increased the true cost spread between credit ratings in the current period. The current premiums for bond insurance have attracted new entrants into this market and it could continue to attract new entrants that could decrease the cost of bond insurance from current levels and thus decrease the cost differential in credit spreads. Current legislative developments could have the federal government assume some of the risks and costs that have been historical been borne by private banks. Additional capital infusions into private banks to improve their financial stability, should additional loan loss reserves be required, could increase the overall cost of credit. These factors along with other current changes taking place in credit markets could change the expectation of credit spreads between the current time period and the time when the final Supplemental Proposal is published.

In prior rate case proceedings, BPA has not revised the financing analysis between the Initial Proposal and the Final Proposal. There should be a clear and compelling reason to use a revised financing cost study. The basis point spread used in the initial Supplemental Proposal should meet a "reasonable man standard" of no longer representing a reasonable projection of the spread that will occur over the rate test period. If the financing study were revised it would also be necessary for us to also revise the forecast of interest rates projected to be incurred in the Program Case during the rate test period.

Given that the spread used for 20-year conservation financing bonds was 19 basis points in the 7(b)(2) Case for the Initial Proposal and that OPUC is in support of approximately a 24-26 basis point spread, it is apparent that the impact of this change in conducting the rate test would not be material to the amount of rate protection provided by the rate test. We would like to leave open the possibility of updating the financing study for the final Supplemental Proposal based on how changes that are occurring in credit markets appear at the time the final rate proposal is prepared. A decision to update the study would be based on the opinion of BPA's financial advisor that fundamental changes have occurred in credit markets that have impacted credit spreads from the time that the Supplemental Proposal's financing cost study was prepared and that the initial financing study no longer represents a reasonable projection of the spreads that will occur over the rate test period. If a decision were made to update the financing cost study it would still rely on historical averages of the difference in credit spreads with more weight given to recent bond issuances.

Q. The OPUC notes that BPA's rationale for selecting the period FY 1998-2007 was that "[w]e feel that the economic conditions and interest rates of the past ten years have a greater likelihood of being replicated than do the conditions of the early 1980s." Hellman and McGovern, WP-07-E-PU-1 at 29. The OPUC argues that BPA should place greater focus on modeling the spreads associated with the future test period than on ruling out high interest rates from the 1980s. Id. With current trends pointing towards higher spreads and spread differentials between A and AA rated bonds, BPA should obtain forecasts of spreads for the future years. Id. Absent the availability of a forecast, BPA, at a minimum, should compare its current forecast to present times and place greater weight on recent history. Id. For example, if BPA used the last 3, 5, or 7 year time period, it would have found a differential of 21, 23, and 22 basis points rather than the 19 basis point differential shown in Table C. Id. Do you agree?

A. Tax exempt interest rates can fluctuate within a year due to a number of factors. Some of these factors have a short durational impact while others have a longer impact. Interest rates can change based on expectations surrounding financial markets, inflation forecasts, the number of public financings and the credit quality associated with those financings that are being undertaken (demand for capital) and the availability of credit (supply of capital) to the bond markets during a segment of time, absolute levels of interest rates, and other changes occurring in the economy at that time. The advantage of using historical averages is that they dampen out the peaks and valleys associated with interest rates over time and are a more reasonable and stable estimate of projected interest rates over longer time periods (FY 2009-2013). Current interest rate projections that are influenced more heavily by current interest rate trends can change over the course of a year and lack the stability of long-term averages. Current interest rate projections are being influenced by current disruptions in credit markets associated with sub-prime mortgages. It would be unlikely that these current forecast factors would continue over the entire rate test period.

Since FY 1985, BPA has contracted with four different financial advisors to provide the financing cost study used in conducting the 7(b)(2) rate test. All of these studies have used historical averages based on actual bond issuances that have taken place in the credit markets. All of these financial advisors indicated that the use of historical averages reflecting actual bond issuances in the market were more reliable in predicting future tax exempt interest rates during the rate test period than a single forecast of future interest rate spreads by a single financial advisor. We believe the current rate case and future rate cases would not benefit by departing from using historical averages as a basis for projecting the spreads that would occur during the rate test period.

As outlined in the prior response, we will evaluate the need to update the financing study prior to preparing the final Supplemental Proposal. If the decision is made to update the financing study, it would continue to rely on historical averages of the difference in credit spreads with more weight given to recent bond issuances.

Q. *The OPUC argues that the rate differential that best represents the financing benefits associated with BPA's participation in resource acquisitions of BPA-sponsored conservation and generation resources by public utilities would be to give more weight to recent history and including current bond spread differentials suggests a financing benefit of 25 basis points would be more accurate. Hellman and McGovern, WP-07-E-PU-1 at 29. The OPUC notes that it obtained the current information for A and AA rated bonds from PacifiCorp. Id. According to that data, the three, five and seven year average spread between A and AA* *rated bonds was 26, 24 and 26 basis points, respectively. Id. The data provided interest rates up to February 2008 and is attached as WP-07-E-PU-1 at A5. Id. Do you agree?*

A. As pointed out in the preceding responses, it is unclear whether current projections of spreads between credit ratings will continue to increase, stay the same, or whether the current spread will decrease in the near future before finding stability at a new lower equilibrium point. It is unclear at this time whether a spread of 24-26 basis points between bonds issued with a single A or double AA credit rating is the best estimate to use in performing the rate test for FY 2009-2013. BPA will evaluate the need to update the financing study prior to preparing the final Supplemental Proposal. If the decision is made to update the financing study, it would rely on historical averages of the difference in credit spreads with more weight given to recent bond issuances.

Section 9: Conservation Accounting Treatments and Financing Conservation Costs

Q. The PPC argues that in the Supplemental Proposal BPA simply uses the historical financing and capitalization amounts for each year of programmatic conservation assumed to be an available resource in the 7(b)(2) Case. O'Meara, et al., WP-07-E-PP-9 at 16. As a result, the amounts and percentages of costs that are expensed and capitalized vary from resource to resource; in general, a relatively high amount is expensed in the year that the resource is assumed to be brought on line to meet load. Id. Do you agree?

A. We generally agree with this statement. But some additional facts surrounding how conservation costs have changed through the years and how their cost treatment differs in the Program Case from their cost development in the 7(b)(2)

Case might provide some additional understanding concerning the treatment of conservation costs.

Q. *Please compare and contrast the amount of historical conservation expenditures that were expensed and capitalized with the amounts of projected conservation expenditures that were expensed and capitalized in the 7(b)(2) Case.*

A. Our historical and projected conservation costs and savings are presented in the Section 7(b)(2) Rate Test Study, WP-07-FS-BPA-06, Appendix D at D-22. This page presents the subtotal for historical conservation costs as adjusted for the 7(b)(2) Case for FY 1982-2004. The total conservation expenditures stated in the nominal dollars for the year in which they were acquired for this period is $1,933.2 million. Of this amount, $571.8 million was expensed (29.6%) and $1,361.4 million was capitalized (70.4%). In contrast, the projected conservation expenditures stated in nominal dollars for the respective year as adjusted for the 7(b)(2) Case for the years FY 2005-2013 total $1,006.6 million. Of this amount, $684.1 million was expensed (68.0%) and $322.5 million was capitalized (32.0%).

Recent conservation efforts such as market transformation efforts are designed to increase the awareness of energy conservation and the use of energy devices such as compact fluorescent light bulbs and to encourage consumers to purchase more energy efficiency appliances. Thus, the current composite amount of conservation expenditures acquired since FY 2004 has a significantly higher amount of items that are properly expensed in the period incurred and not capitalized and debt financed in BPA's financial records, which reflects their treatment in the Program Case.

Q. *Please explain how conservation costs are developed in the Program Case.*

A. Although the amount of historical conservation expenditures that are expensed or capitalized and financed with debt is the same for the Program Case and the 7(b)(2) Case, the treatment of how conservation costs are developed in the two Cases is quite different. In the Program Case, the conservation costs are the expensed costs for each year's conservation program plus the amortization expense associated with prior years' capitalized conservation. Amortization expense plus minimum required net revenues meet BPA's debt service requirements. Total Program Case Conservation costs ranged from $159 million in FY 2009 to $169 million in FY 2013. In the Program Case, operating expenses net of amortization expense range from $108-114 million dollars per year during the rate test period and they comprise approximately 66 percent of the total conservation expenditures. The amortization expense in the Program Case revenue requirement consists of three different amortization treatments for prior and projected capitalized conservation expenditures. Program Case conservation amortization expense ranges from $51-63 million dollars per year and comprises 34 percent of the total conservation expenditures. Capitalized conservation investments relating to the years FY 1982-2001 (Legacy Conservation Investments) were amortized over 20 years. Thus, the Program Case Revenue requirement for FY 2009 contains amortization expense associated with capitalized Legacy conservation investment for the years FY 1989-2001. Capitalized conservation investments relating to the years FY 2002-2007 (ConAug Conservation Investments) were amortized over a declining 10-year time period. Capitalized FY 2002 conservation investments were amortized over 10 years, while FY 2006 conservation investments were amortized over 6 years. All ConAug conservation investments are fully amortized by the end of FY 2011 in the Program Case. Capitalized conservation investments relating to the years

FY 2007-2013 (Conservation Acquisitions) are amortized over a 5-year time period in the Program Case.

Q. Please explain how conservation costs are developed in the 7(b)(2) Case.

A. In comparison to the Program Case, the costs in the 7(b)(2) Case for FY 2009 comprise the expensed operating year costs for the years FY 1994-2005, 2009, and 2012-2013 along with the debt service associated with the capitalized conservation expenditures for just those respective investments. The debt maturity period for capitalized conservation costs is 20 years for conservation investments relating to FY 1982-2001. This debt maturity period matches the amortization time period for these historical conservation investments in BPA's financial records as reflected in the Program Case. The debt maturity period for conservation investments relating to FY 2002-2013 is 15 years in the 7(b)(2) Case. This is a significantly longer financing period than the Program Case which finances conservation incurred after FY 2006 over five years. Debt service in the 7(b)(2) Case assumes mortgage type financing (decreasing interest /increasing principal payments over the term). In FY 2010-2013 there are no conservation program operating expenses associated with the investments chosen in FY 2009. The fixed annual level of debt service associated with the 15- or 20-year debt term associated with the year of the investment continues during the remaining years of the rate test period. The 7(b)(2) Case first year operating expenses amounted to \$700.8 million for FY 2009 and then ranged from \$172.6 million in FY 2010 to \$0 in FY 2013. The debt service for FY 2009 amounted to \$57.7 million and increased to \$73.5 million by FY 2013.

Q. Please compare the treatment of conservation costs in the Program Case and the 7(b)(2) Case.

A. As one can see from this synopsis, the treatment of conservation costs is very different between the two Cases. In the Program Case there is a stable amount of operating expense net of amortization expense ($108 to $114 million) in all years of the rate test period. In contrast, there is a much larger up-front amount of accumulated operating expenses associated with each fiscal year's conservation investment in the first year of the rate test period ($700.8 million) that decreases substantially from the first year amounts to $0 in FY 2013 in the 7(b)(2) Case. In the Program Case, amortization expense ranges from $51-$63 million associated with capitalized conservation investments incurred during FY 1989-2013 (replacement for debt service requirements) while in the 7(b)(2) Case there is no amortization expense. Debt service related to the specific conservation investments chosen for the year selected and for each subsequent year of the rate test period ranged from $58-74 million in the 7(b)(2) Case. The principal difference in the two sets of costs is attributable to the multiple years of first year expense costs present in the 7(b)(2) Case.

Q. The PPC argues that although BPA staff has not specifically proposed an alternative assumption for conservation financing, they readily acknowledge that historical financing structures may not be appropriate in the 7(b)(2) Case. O'Meara, et al., WP-07-E-PP-9 at 17. Do you agree?

A. We recognize that whereas annual programmatic conservation comes on one annual program at a time each year in the Program Case, in the 7(b)(2) Case several of these same annual programmatic conservation resources can be brought on in a single year. As a consequence of BPA's annual programmatic conservation being in the 7(b)(2) Case resource stack, some financing assumption other than the actual historical practice may be reasonable in the 7(b)(2) Case.

Therefore, we did not state that the current treatment of conservation financing was inappropriate, but rather other assumptions may be reasonable.

Q. *Does BPA's accounting treatment of conservation costs reflect the nature of the conservation costs and how they are reflected in BPA's financial statements?*

A. Yes. It is important to point out that each vintage year of conservation expense costs represent costs that were appropriately expensed within that year from an accounting standpoint. These expenses do not provide a future economic benefit that extends beyond the year. The expensed costs include energy efficiency program staffing costs, indirect overhead costs, corporate general and administrative costs, market transformation efforts, expense agreement and grants, C&RD costs, along with other expenses of the year. Prudent utility practice and sound business principles generally hold that firms should not borrow money to finance current operating expenses.

Q. *In the 7(b)(2) Case, would the JOA be able to present a credible case of presenting a financing debt structure that would allow it to borrow for these operating expenses?*

A. Generally yes, but with limitations. BPA's accounting treatment for capitalizing a portion of annual conservation investments is based on the determination that the specific conservation expenditure associated with the measure provides economic benefits in excess of one year together the provisions of Statement of Financial Accounting Standards (SFAS No. 71) "Accounting for the Effects of Certain Types of Regulation." The JOA and member utilities (governmental bodies) are subject to the financial reporting requirements of the Governmental Accounting Standards Board (GASB). The GASB has not issued an accounting standard for governmental bodies similar to SFAS No. 71. However, the JOA and its member entities that are operating in a rate regulated environment should be able to rely on

SFAS No. 71. As a result, the JOA and the member utilities would be able to capitalize and defer these expenses as intangible regulatory assets as long as they could demonstrate that they were recoverable in future rates. These deferred regulatory assets only have value if they can be recovered in rates over future time periods. Under deregulation of utility rates, auditors and rating agencies have expressed concerns that deferred costs such as intangible conservation expenses could become stranded utility costs, that is, costs that are not recoverable in rates and thus written off as a loss. Sound business practices and prudent utility practices would temper the accumulated amount of deferred regulatory assets that are present in a utility's balance sheet.

Q. From a ratemaking perspective, what is the appropriate balance to reach in preventing "rate shock" from ramping up a massive conservation program (represented by the cumulative amount of first year conservation costs) that parties have argued against versus concerns for not accumulating a bow wave of deferred costs that could possibly not be supported by sound business and accounting practices?"

A. We propose an alternative that would significantly reduce the front loading of operating expenses associated with conservation program acquisition in the 7(b)(2) Case while balancing the need to match current rates with current costs and not accumulate an excessive amount of deferred costs in the form of regulatory assets. The JOA and the member utilities would still have to provide the funds to pay for the cumulative amount of operating expenses that are being deferred from current rates. These deferred costs/regulatory assets could be borrowed for under an operating line of credit that would carry a higher interest rate (projected average prime interest rate per Global Insight's average for FY 2009-2013 =7.29%) for the rate test period, prime rate plus a margin of 1-2%

typical of such loans, and the term of the loans would be shorter given the nature of the costs. The operating line of credit loan would be secured with the utility revenues from each utility member of the JOA (this security for the loan is similar to the SFAS No. 71 requirement that in order to defer the costs they must be recoverable from future rates). Typical maturity terms for operating lines of credit loans are generally 3-5 years. Typically the JOA member entities, cities and county governmental bodies and cooperatives would not want the associated liabilities on their balance sheets, so the amount of the corresponding liabilities should be limited.

We propose that the term of the operating line of credit loan carry a maturity term of five years for respective cumulative first year costs for each rate test period year. Debt maturities for conservation expenditures that have been historically capitalized would remain the same as the current rate test practice. Capitalized conservation expenditures for FY 2001 and prior would be financed with debt over a 20-year term. Capitalized conservation expenditures for FY 2002 and later years would be financed over a 15-year term. In the FY 2009-2013 rate test period, the cumulative first year operating expenses for FY 2009 comprising FY 1994-2005, 2009, and 2012-2013, which total $700.8 million dollars, would be financed over five years using the operating line of credit loan (debt service for 5-year term, interest rate of 8.25% = $171.5 million per year). For FY 2010 the cumulative first year operating expenses total $64.7 million that would be financed over five years (FY 2010-2014) using an additional increment of the operating line of credit loan. This alternative would spread the first year operating expense costs evenly over a rolling five-year period that would replace the front loading of these costs under current practice.

We are open to reviewing the record to consider other alternative financing treatments for dealing with the cumulative first year expensed costs that address: (1) the SFAS No. 71 accounting treatment for such costs; (2) concerns over accumulating an excessive amount of deferred costs/regulatory assets; (3) a financing treatment for the deferred costs/regulatory assets that is supported by current financing practices; and (4) a levelized cost selection metric for conservation resources.

Q. *The PPC argues there are problems with using the historical financing assumptions. O'Meara, et al., WP-07-E-PP-9 at 17. First, the manner in which conservation is acquired in the 7(b)(2) Case is fundamentally different from the Program Case, and from any actual circumstance faced by regional utilities when operating a BPA conservation program. Id. While in the Program Case, BPA's annual programmatic conservation is brought on and the expense portion paid for one year at a time, in the 7(b)(2) Case many years of annual conservation programs can be brought on from the resource stack (the term used by BPA to describe resources deemed available to serve preference loads in the 7(b)(2) Case) in one year. Id. For example, in BPA's model of the FY 2009 Residential Exchange, fifteen years of annual programmatic conservation are brought on line from the 7(b)(2) resource stack to meet load just in 2009. Id. It is unreasonable to assume that the same financing choices to achieve an amount of conservation over 15 years would be used to achieve the same amount in a single year. Id. In fact, the historical assumptions result in an average cost of approximately $160/MWh for the 542 aMW of conservation used for 2009 in the 7(b)(2) Case. Id. The situation is even more extreme for 2010. Historical financing assumptions result in an average cost of approximately $302/MWh for the 68 aMW conservation brought on in that year Id.. Such decisions would be* *highly uneconomical and unreasonable, and it is inappropriate to assume that utilities would have financed conservation in this manner in the absence of BPA conservation programs. Id. Do you agree?*

A. We agree with PPC's representation of the costs cited. However, the higher first-year cost of conservation and generation resources is an industry norm and is not necessarily tied to the number of conservation resources brought on from the 7(b)(2) resource stack in any one year. PPC's own calculations show that the average first year cost of bringing on 542 aMW of conservation in 2009 was about $160/MWh, while in the next year 68 aMW was brought on at a first year cost of about $302/MWh. Indeed, in 2011 and 2012, only one conservation resource is brought on per year, much as in the Program Case, with first year costs of $247 and $311/MWh respectively. Therefore, the higher first year cost of conservation resources is not a function of the number of these resources brought on in one year, but rather the natural consequence of expensing appropriate costs in the first year. Even assuming that just one conservation resource is brought on per year as in the Program Case, that conservation resource will have a much higher first year cost than the levelized cost of the resource over its projected lifetime. Because the first year cost of conservation resources actually purchased in the Program Case is as high as those available in the 7(b)(2) resource stack, the decision as to whether a conservation resource was cost-effective was made on the basis of the useful life cost rather than the first year cost. As outlined in the previous response, different financing methods for the aggregated first-year expensed costs may be reasonable.

Q. The PPC also argues that another problem with using the historical financing assumptions is that in the 7(b)(2) Case BPA assumes that it acquires conservation from a JOA formed of regional consumer-owned utilities. O'Meara, et al., *WP-07-E-PP-9 at 18. In financing its own conservation programs in any given year BPA must consider a myriad of factors that are unique to its own situation. Id. These factors include preserving adequate Treasury borrowing authority, optimally managing its non-federal debt such as Energy Northwest, and maintaining adequate liquidity to cover its operating costs. Id. A JOA formed from consumer-owned utilities would not have these BPA-specific concerns and limitations. Id. Indeed, such a JOA would have an important interest in acquiring resources in such a manner as to sustain power rates for its constituents at the lowest and most stable levels. Id. This interest conflicts with expense financing a massive amount of conservation resources through rates in a single year. Id. Do you agree?*

A. No. The financial pressures on the hypothetical JOA would be similar to the financial pressures faced by BPA,that is, they would have debt covenants that would have minimum required debt coverage ratios that would have to be maintained. The individual utility boards would probably mandate a coverage level above the minimum level specified in the debt issues. They would have to follow GASB pronouncements if they wanted a clean annual audit opinion. In addition, they would likely elect to implement Financial Accounting Standards Board (FASB) statements and interpretations, especially SFAS No.71. BPA and the JOA would be governmental entities operating in the electric utility industry. Financially they would be more alike than is characterized by the PPC.

Q. The PPC proposes that BPA assume that the JOA would fully capitalize the costs of conservation resources in the 7(b)(2) Case and amortize those costs over the useful lives of the resources. O'Meara, et al., WP-07-E-PP-9 at 18. Do you agree?

A. No. We believe the JOA would capitalize, amortize, and finance conservation measures that have a useful life beyond one year over a period of 20 or 15 years as previously outlined. As we have previously stated, conservation programs occurring after FY 2004 had 68 percent of their expenditures expensed in the year incurred. The JOA would elect to treat the large amount of conservation expenses (cumulative years of expensed conservation expenditures chosen from the resource stack) as deferred regulatory assets and amortize them over a relatively short period of three to five years.

Q. Did you properly account for the costs of future conservation programs acquired in the 7(b)(2) Case?

A. Yes. As outlined earlier in this testimony, the cumulative first year expensed costs were properly classified as expenses of the year they were incurred. Expensed costs are not costs that provide an economic benefit beyond the current year, thus they are not expenditures that are appropriately capitalized with other costs that do provide an economic benefit beyond the current year. It is only under a regulatory setting that utilities defer these expenses under SFAS No.71.

Our proposal to have the JOA account for the large amount of conservation expenses as deferred costs/regulatory assets under SFAS No.71 smoothes out the "rate shock" that occurs in the 7(b)(2) Case. This proposal addresses both the "rate shock" concerns associated with ramping up a massive conservation program (represented by the cumulative amount of first year conservation costs) and the concern for not accumulating a bow wave of deferred costs that could possibly grow to a level where they might not be recoverable through rates in future years.

The proposal also reflects realistic lending practices by financial institutions for operating lines of credit or other practices that would be applicable to financing deferred costs/regulatory assets. We propose that the cumulative first year operating costs be financed with a shorter 5-year term operating expense loan. The nature of the deferred expenses/regulatory assets would retain their identity, and the financing treatment of these costs over a shorter term at a higher interest rate would be more consistent with current lending practices.

Q. The PPC argues that its proposed changes make more sense than the historical financing assumptions because fully capitalizing and amortizing the costs of conservation resources acquired by the JOA would be consistent with the JOA's goal and interest of maintaining stable and low rates for its member utilities, as opposed to BPA's historical financing assumptions which are based on factors relevant to an annually implemented conservation program, and which have no real bearing on the hypothetical presented in section 7(b)(2). O'Meara, et al., WP-07-E-PP-9 at 19. Do you agree?

A. No, for the reasons cited in the previous response and because the PPC is not fully describing the JOA's goals and interests, which they limit to "maintaining stable and low rates for its member utilities." The PPC has forgotten that the JOA would also want to adopt the corollary goal of operating in a manner that is consistent with sound business principles. Conducting their operations under sound business principles would require the JOA to: (1) be cognizant of matching the current costs of operations through current rates; (2) adopting accounting policies that are consistent with GASB and FASB pronouncements; (3) maintaining high credit ratings so that the cost of financing their operations would be low; and (4) maintaining adequate financial reserves for operations and to meet or exceed debt coverage ratio requirements associated with bond covenants and operating lines of credit.

Q. The PPC argues that leaving all other assumptions in the model as they are, fully capitalizing and debt financing conservation resources in the 7(b)(2) Case has the effect of increasing the rate test trigger from 5.2 mills/kWh to 7.1 mills/kWh. O'Meara, et al., WP-07-E-PP-9 at 19. Rate protection for 7(b)(2) customers increases from approximately $327 million to approximately $447 million. Id. Do you agree?

A. We agree that if PPC's total capitalization of conservation proposal were adopted the above model results would be a reasonable representation. We do not agree with PPC's proposal to capitalize all conservation expenditures and to amortize and finance them over a period of fifteen years.

Q. The PPC argues that resources in the 7(b)(2) Case are sorted in order of cost based on the average cost of their output over their useful life (i.e., total capital and total O&M costs divided by total output). O'Meara, et al., WP-07-E-PP-9 at 19. However, if some portion of the cost is expensed, then the cost of a conservation resource in the year it is brought on to serve load in the 7(b)(2) Case may not correspond to its position in the resource stack, meaning that resources are not brought on in "least-cost" order. Id. Do you agree?

A. No. Using levelized costs when comparing different types of resources with different financing methods and different useful lives is the industry standard. However, we do recognize that its vintage conservation expenses are unique in that they only have an expense component in the first year as compared to other resources that have ongoing operating and maintenance expenses for all years of their operation. Expenses are costs of the year when they are incurred unless they are deferred under an applicable Generally Accepted Accounting Principle such as SFAS No. 71. Our proposed treatment of deferring the accumulated first year costs in the 7(b)(2) Case and amortizing them and financing them over a five-year period partially addresses PPC's concerns about the selection of conservation resources based on their levelized costs.

Q. *The PPC argues the following example illustrates its point. O'Meara, et al., WP-07-E-PP-9 at 20. The first conservation resource in the 7(b)(2) Case resource stack is the 2001 BPA Programmatic Conservation. Id. The resource was sorted on the basis of a levelized cost of $3.34/MWh expressed in 1980 currency. Id. However, under BPA's historical financing assumptions, this resource is brought on to serve load in the 7(b)(2) Case for 2009 at a cost of $64.80/MWh in 1980 currency. Id. This is almost 20 times as expensive as the cost basis on which the resource was sorted and selected from resource stack. Id. In other words, the average cost used to rank resources is not the cost that is recovered from the 7(b)(2) Case rates. Id. In contrast, in BPA' s model, Cowlitz Falls is the last resource brought on from the stack in the 7(b)(2) Case for 2009. Id. Cowlitz Falls operates at a cost of $28.61/MWh in 1980 currency, and the 7(b)(2) Case rates recover only the $28.61/MWh, not some higher (or lower) amount. Id. This is just one example of how resource costs are not properly translated in least-cost order into rates in the 7(b)(2) Case. Id. Do you agree?*

A. No. As stated above, the use of levelized cost over the useful life of a resource is the industry standard when comparing different types of resources. In PPC's example of the 2001 programmatic conservation resource, the first year case is in fact about $64.80/MWh in 1980 dollars in the first year. However, in the next 19 years the cost is $0.015/MWh in 1980 dollars. Therefore, the average cost of the 2001 programmatic conservation resource is about $3.3/MWh in 1980 dollars, which coincides with the levelized cost used to position it in the resource stack.

Q. *The PPC argues that this problem does not affect the results on the rate test trigger if PPC's recommendations regarding conservation financing assumptions* *in the 7(b)(2) Case are adopted. O'Meara, et al., WP-07-E-PP-9 at 20. When conservation in the stack is fully debt financed and amortized, the levelized cost that forms the basis for sorting and selection is also the cost recovered from rates in the 7(b)(2) Case. Id. However, especially to the extent that BPA does not adopt the recommendation for full capitalization and debt financing of conservation resources in the 7(b)(2) stack, this is a flaw in the model that needs to be corrected and which does have a substantial impact on the rate test results. Id. Do you agree?*

A. No. The PPC proposal is too simplistic. It fails to consider the nature of these costs that were appropriately treated as expense costs in the year they were incurred. It lumps all costs, both expensed and properly capitalized costs, into the same pot and assumes that 15-year bonds could be issued by the JOA for its financing with the same current estimated financing costs that apply to the historical capitalized portion of conservation expenditures. The PPC proposal does not reflect realistic lending practices by financial institutions for operating lines of credit or other practices that would be applicable to financing deferred costs/regulatory assets that are the true nature of these costs.

As stated above, a possible solution to the PPC's concern over high first year conservation resource costs is that the cumulative first year operating costs be financed with a shorter 5-year term operating expense loan. The nature of the deferred expenses/regulatory assets would retain their identity, and the financing treatment of these costs over a shorter term at a higher interest rate would be more consistent with current lending practices.

PPC's proposal of treating all costs as being capitalized and financed over 15 years would solve the PPC's perceived levelized cost selection problem associated with having all the accumulated first year expense costs spread over the useful life of these assets as PPC has defined their useful life. The problem is that a substantial portion of these costs have a useful life that is less than this period of time. Incorporating the concept of deferred costs and regulatory assets would change the treatment of these first year expensed costs to costs that could be spread over a shorter period of time than what the PPC proposes. BPA's proposal significantly addresses the first year "rate shock" problem that is inherent in the current treatment. The current levelized cost determination would average these deferred costs as if they occurred over the full 20- or 15-year useful life time period as opposed to the actual cash flows that occur over a five-year time period.

Q. *WPAG does not agree with BPA's proposed treatment of conservation but, if BPA does not adopt the preference customers' proposed approach, WPAG offers an alternative approach. Grinberg, et al., WP-07-E-WA-05 at 28. WPAG argues that because a large share of the annual conservation program costs is expensed, the cost of the conservation resources is significantly overstated using the above method. Id. Do you agree?*

A. We do not agree. We do not discern an alternative approach from WPAG to the issues surrounding the capitalization and financing of conservation raised in PPC's testimony. Please refer to our response to PPC above.

Q. *WPAG argues that the historical pattern funding for conservation is not reflective of what preference customers would do absent the BPA conservation program, and particularly under the Joint Operating Agency assumed by BPA in the 7(b)(2) rate test. Grinberg, et al., WP-07-E-WA-05 at 28. In such a situation, preference customers would follow their normal pattern for the financing of long-lived resources, which is to match the financing with the expected useful life of the resource. Id. This is done to more closely match the cost and benefits of the* *resource, and to avoid intergenerational equity issues. Id. Further, where the preference customers could take advantage of tax-exempt financing to acquire these resources, it is much more logical to assume that they would pursue the least cost financing option of financing the entire conservation resource with debt. Id. Do you agree?*

A. We do not agree WPAG's position fails to recognize that a substantial amount of each year's conservation costs were costs that were properly expensed in the year incurred. These were expenses for which there was no measurable economic benefit beyond the year incurred. They comprised salaries of BPA's Energy Efficiency staff, general and administrative overhead charges, market transformation expenditures that are similar to advertising costs in that they are costs for advertising and promotional materials and programs to encourage consumers to purchase energy, and other costs that are properly expensed in the year incurred. As we outlined in our response to PPC above, these costs could be capitalized as intangible assets as deferred costs/regulatory assets under Statement of Financial Accounting Standards (SFAS) No. 71, "Accounting for the Effects of Certain Types of Regulation," but they should be treated separately from the expenditures that were correctly capitalized, which provide economic benefits beyond the year incurred. In our response to the PPC above, we outlined additional business and financing arguments surrounding the borrowing costs and the maturity of debt that would be used to finance deferred charges/regulatory assets. WPAG's position on this issue treats all the expenditures, both capital and expense, as similar costs that can be financed under the same costs and terms. We disagree with the position on these issues taken by WPAG and PPC.

Q. WPAG argues BPA should assume that conservation will be entirely capitalized in its recalculation of the section 7(b)(2) rate test in both the WP-02 and WP-07 cases. Grinberg, et al., WP-07-E-WA-05 at 28. Do you agree?

A. We do not agree with WPAG's proposal for the reasons previously cited in this testimony.

Section 10: Obsolete Conservation

Q. The PPC argues that its understanding of what each conservation resource in the 7(b)(2) Case represents is that each of these conservation resources represents the aggregate total conservation achieved in a given year through BPA's conservation programs. O'Meara, et al., WP-07-E-PP-9 at 26. Thus, the total "Nameplate Capacity" value is the sum of all the energy efficiency savings garnered from a wide variety of measures. Id. Each of these measures has a potentially different useful life. Id. Do you agree?

A. Yes. Each individual year of conservation investment is an aggregation of all the different conservation measures for the respective year. The types of conservation investments/measures change over the years and the mix of individual measure costs and their related savings is unique to each year's conservation investment. Theoretically, it would be possible to break out the individual measures and their different useful lives. BPA's financial records did not to break out the individual measures for each respective year. It was much more practical, while still correctly accounting for conservation costs, to use the Council's composite useful life of conservation measures, which was 20 years for FY 1982-2001 and 15 years for conservation measures incurred after FY 2001 to establish the JOA's conservation amortization and debt maturity periods.

Q. Although the PPC generally supports excluding obsolete conservation measures from the 7(b)(2) Case, the standard BPA uses in the rate test to define obsolete conservation is inappropriate. O'Meara, et al., WP-07-E-PP-9 at 26-27. Given the varied nature of BPA conservation programs within and between years, BPA has provided no rationale to simply assume that the useful life of conservation programs implemented prior to 2001 is 20 years. Id. Do you agree?

A. No. The conservation amortization policies and the fact that they were based on the Council's estimate of the composite useful lives is explicitly stated in a number of places in the WP-07 Final Proposal documents and the WP-07 Supplemental Proposal documentation. A portion of those citations are Keep, *et al.*, WP-07-E-BPA-27 at 21: Doubleday, *et al.*, WP-07-E-BPA-60 at 25-26: and Keep, *et al.*, WP-07-E-BPA-68 at 14-15.

For conservation measures that occurred during FY 1982-2001, we asked the Council to provide BPA with the effective composite useful life of the conservation measures that comprised the Council's list of cost-effective conservation measures. The Council informed us that this composite useful life was 20 years for this period of time. BPA's financial records and the treatment of these costs (Legacy Conservation Program Capitalized Costs) in the Program Case reflect this 20-year amortization period. For comparability of costs between the Program Case and the 7(b)(2) Case in performing the rate test, it is important that the 7(b)(2) Case JOA's amortization period match the historical BPA amortization policy pertaining to FY 1982-2001 conservation investments.

In the years after FY 2001, other financial considerations concerning extending the availability of BPA's limited Treasury borrowing authority directed BPA to change its conservation amortization policy. Capitalized conservation investments relating to the years FY 2002-2007 (ConAug Conservation

Investments) were amortized over a declining 10-year time period. Capitalized conservation investments relating to the years FY 2007-2013 (Conservation Acquisitions) are amortized over a 5-year time period in the Program Case. For the same reasons as outlined by the PPC above ("the JOA's goal and interest of maintaining stable and low rates for its member utilities, as opposed to BPA's historical financing assumptions which are based on factors relevant to an annually implemented conservation program, and which have no real bearing on the hypothetical presented in section 7(b)(2)"), BPA assumed that the JOA's amortization policy should reflect the goal of maintaining stable and low rates for its member utilities. Again, BPA relied on the Council's expertise for the composite useful life of conservation investment occurred after FY 2001 of 15 years.

Q. *The PPC argues that although there is no single, industry accepted standard for measuring the effective life of conservation measures, there are some extant studies that shed light on the realistic useful lives of various conservation measures. O'Meara, et al., WP-07-E-PP-9 at 27. One such study PPC reviewed is the "Measure Life Report- Residential and Commercial/Industrial Lighting and HVAC Measures" prepared by GDS Associates for use in evaluating the effectiveness of various common energy efficiency measures. See WP-07-E-PP-10, Attachment 7. Although some measures have expected lives of 20 years, many common measures in all sectors (residential, commercial, and industrial) have expected useful lives of only 8-15 years. Id. This implies that BPA's assumption that the average life of their various measures in any given year might be overly optimistic. Id. Do you agree?*

A. No. It was reasonable for us to rely on the Council for the determination of the composite conservation measure lives for the two different amortization periods that are used in the 7(b)(2) Case. It is the Council that develops the list of cost-effective conservation measures and practices to be adopted in the Pacific Northwest and it had the expertise to advise us on the composite useful lives of conservation investments. The Council provides the region with comprehensive 5-year power plans that outline the updated list of cost-effective conservation measures and other suggested resource investments to meet the region's loads. It is in the Council's interest to provide objective and reasonable estimates of conservation useful lives because its comprehensive 5-year power plans rely on these same estimates.

As outlined in the response above, a more important reason to use the 20-year amortization period for FY 1982-2001 conservation investments is to maintain the comparability of costs between the Program Case and the 7(b)(2) Case in performing the rate test. It is important that the 7(b)(2) Case JOA's amortization period match the historical BPA amortization policy pertaining to FY 1982-2001 conservation investments.

Q. *The PPC argues that it has reviewed a report titled "Measure Life Study II," which was prepared for BPA by Skumatz Economic Research Associates specifically to evaluate the effective life of various conservation measures. See WP-07-E-PP-10, Attachment 8. O'Meara, et al., WP-07-E-PP-9 at 27-28. The relevant conclusions are similar to those found in the "Measure Life Report-Residential and Commercial/Industrial Lighting and HVAC Measures" report cited above. See pp. III-9 through III-11 of WP-07-E-PP-10, Attachment 8. Would it be reasonable to rely on such conclusions?*

A. No, for the reasons outlined in the previous response.

Q. *The PPC recommends assuming a useful life of no more than 15 years for all of BPA's programmatic conservation. O'Meara, et al., WP-07-E-PP-9 at 28. PPC* *states this seems like a more reasonable average considering the varied nature of conservation measures adopted by BPA in any given year. Id. Further, 15 years is already the useful life BPA is assuming in the models for conservation implemented after 2001. Id. Thus, to the extent that the composition of BPA's annual programmatic conservation is variable and not documented in detail in BPA's testimony or studies in this proceeding, PPC's recommendation provides an assumption that is more consistent within the model as well as with common industry practice. Id. Do you agree?*

A. No, for the reasons cited in the previous responses.

Q. The PPC argues that leaving all other assumptions of BPA's proposal as is, its proposed changes result in an increase in the rate test trigger to 6.5 mills/kWh and increase rate protection to the 7(b)(2) Customers to approximately S409 million. O'Meara, et al., WP-07-E-PP-9 at 28. Do you agree?

A. The PPC's model results appear to be calculated correctly if their proposed changes were adopted.

Q. If PPC's arguments were adopted, resulting in a 6.5 mills/kWh trigger, what Residential Exchange Program benefits would be provided to the residential and small farm consumers of regional utilities?

A. If the rate test trigger were 6.5 mills/kWh, there would be a very small amount of Residential Exchange Program benefits provided to residential and small farm consumers of regional utilities.

Q. The OPUC notes that BPA does not increase the 7(b)(2) Case loads for obsolete conservation, but BPA still makes the obsolete conservation available for the 7(b)(2) resource stack. Hellman and McGovern, WP-07-E-PU-1 at 24. BPA modeling allows for conservation more than twenty years old as of the study-year date to be included in the resource stack. Id. In Response to Data Request No.

AP-BPA-79, BPA states that "conservation investments [which] occurred between 1982 and 2001, had a 20-year service life based on the average life of the types of measures being funded." Id. Assuming a 20-year service life, the use of a single-year demarcation point such as 201, for all vintages of conservation and all years of the study perio, is not sufficient. Id. To be consistent, any conservation resource that is more than 20 years old should not be allowed in the resource stack, given that BPA has determined that a conservation resource is obsolete after twenty years. Id. Do you agree?

A. No. This is the first BPA rate proceeding where BPA has addressed the issue of obsolete conservation resources. In determining whether a resource was available to serve 7(b)(2) Case loads, BPA relied upon the composite useful lives based on estimates developed by the Council. The Council has indicated that the composite useful life associated with the broad number of different types of approved conservation measures contained in the Council's plan for FY 1982-2001 was on average 20 years. Council staff indicated that the composite useful life associated with conservation investments made after FY 2001 is on average 15 years. We adopted a policy for the Supplemental Proposal that resources that became fully amortized before the end of the rate test period would not be available to serve 7(b)(2) Case loads. We pointed out in Response to Data Request No. PP-BPA-37 that we had not followed this policy consistently in performing the rate test for each of the three rate test periods; FY 2002-2006, FY 2007-2008, and FY 2009 in the Supplemental Proposal, and that we would be correcting this inconsistency in the final Supplemental Proposal. That data response clearly demonstrates that the demarcation point for determining obsolete conservation resources changes in relationship to the applicable rate test study period. The load/resource balance difference between the Program Case and the

7(b)(2) Case also changes in relationship to the population of conservation resources that are available to meet 7(b)(2) preference loads and are in the resource stack. The FY 2016 study year was beyond the rate test study period and therefore had no bearing on the Supplemental Proposal's rate test results. The results of the proposed practice in determining which conservation resources have become obsolete and the load/resource balance difference between the Program Case and the 7(b)(2) Case are outlined below for the three rate study periods.

For the FY 2002-2006 rate test period, conservation investments undertaken during FY 1982-FY1990 are proposed to be obsolete, because all of these resources were fully amortized before FY 2010, the last year of the rate test period (FY 1990 plus 20 years of amortization occurs prior to the end of FY 2010). The 7(b)(2) Case loads are increased at the beginning of the rate test period by the amount of conservation resources in the resource stack for FY 1991-2001 totaling 441.1 aMW, together with the amount of billing credit resources that are included in the resource stack of 17.5 aMW, for a total of 458.6 aMW.

For the FY 2007-2008 and FY 2009 rate test periods, conservation investments undertaken during FY 1982-1993 are proposed to be obsolete, because all of these resources were fully amortized before FY 2013, the last year of the rate test period (FY 1993 plus 20 years of amortization occurs prior to the end of FY 2013). BPA will increase the 7(b)(2) Case loads at the beginning of the FY 2007 rate test period by the amount of conservation resources investments that were not undertaken and that were included in the resource stack for FY 1994-2006 that totaled 454.7 aMW, together with the amount of billing credit resources included in the resource stack of 17.5 aMW, for a total of 472.2 aMW. BPA will increase the 7(b)(2) Case loads at the beginning of the FY 2009 rate test period by the amount of conservation resources investments that were not undertaken and that were included in the resource stack for FY 1994-2008 that totaled 520.7 aMW, together with the amount of billing credit resources included in the resource stack of 17.5 aMW, for a total of 538.2 aMW.

We do not advocate a single year demarcation point to determine which conservation resources have become obsolete and not available to meet 7(b)(2) Customer loads. The temporal relationship does change in reference to the last year of the respective rate test period. The load resource balance difference between the Program Case and the 7(b)(2) Case also changes for the total amount of conservation investments made in the Program Case prior to the first year of the rate test period that have not become obsolete by the end of the respective rate test period. The information that is presented in Appendix D to the Section 7(b)(2) Rate Test Study, WP-07-FS-BPA-06, which formed the basis for the Supplemental Proposal, will be updated for the final Supplemental Proposal based on actual results for FY 2005-2007 (information in the Supplemental Proposal was based on July 2006 forecast projections), which will be updated for the FY 2008 Conservation Resource Energy Data available in May 2008, which will be adjusted for similar changes outlined in the prior Appendix D. In addition, to the extent more current forecast projections for FY 2008-2013 conservation expenditures are available, BPA hopes to update the Final Proposal for that information as well.

Q. *The OPUC proposes that, for a conservation resource, if the resource is more than 20 years old as of the date of the study year period, then the resource should not be available to meet general requirements, and as such, not be listed in the resource stack. Hellman and McGovern, WP-07-E-PU-1 at 25. As a further refinement, to the extent BPA has service lives of conservation resources, those lives could be used instead of the 20-year value. Id. Do you agree?*

A. It is unclear what date (the beginning, middle, or end of the study year period) the OPUC is proposing to use as the demarcation point. As outlined above, our proposed practice excludes conservation resources that became fully amortized before the end of the rate test study period. These resources would not be available to serve 7(b)(2) Case loads and they would not be taken into account in determining the difference in the load/resource balance between the two cases.

We have not undertaken conservation useful life studies and are not aware of other studies related to the useful life of conservation investments that were included in the Council's approved list of conservation measures beyond the two average composite useful life determinations of 20 years for conservation investments occurring between FY 1982-2001 and 15 years for conservation investments occurring after FY 2001 that were developed by Council staff.

Section 11: Reserves

Q. The IOUs argue that secondary energy available from BPA's resources provide reserves. LaBolle, et al., WP-07-E-JP6-08 at 35. BPA's secondary energy can be used to avert particular planning or operating shortages for the benefit of BPA's firm power customers and is available to BPA from its substantial resources. Id. BPA sells its secondary energy in the surplus market only when, and for so long as, BPA determines that it does not need the secondary energy to avert planning or operating shortages. Id. Do you agree?

A. We agree with the IOUs' assertion that secondary energy provides particular value in averting operating shortages. We do not agree that secondary energy provides value in averting planning shortages. As the IOUs have noted, BPA makes secondary market sales when generation exceeds BPA's firm load obligations. However, the reason the generation is termed 'secondary' is that it cannot be counted on as being available on a firm basis. Therefore, BPA cannot plan on secondary energy being present when required; it is only when it actually occurs within an operating year that BPA gains the knowledge that the secondary energy is available. As a result, we recognize the ability of secondary energy to provide operating benefits, but not planning benefits.

Q. The IOUs note that BPA makes substantial sales of secondary energy and, for FY 2009, BPA projects secondary energy sales of 1,732 aMW and secondary energy sales revenues of $575.6 million. LaBolle, et al., WP-07-E-JP6-08 at 36. Do you agree?

A. Yes. However, even if one assumed for the sake of argument that secondary energy provides reserves, secondary energy revenues do not contribute to the provision of reserves. (We note that this discussion is not about financial reserves, and we do not infer from the IOUs' testimony any implied discussion of financial reserves.)

Q. The IOUs argue that BPA's rights to withdraw power sales from the surplus power market provide reserves. LaBolle, et al., WP-07-E-JP6-08 at 36. The IOUs state that BPA's surplus market sales are a major source of its reserves because BPA sells its secondary energy in the surplus market only when, and for so long as, BPA determines that it does not need the secondary energy to avert planning or operating shortages. Id. As a result, the IOUs argue BPA's surplus market sales provide electric power needed to avert particular planning or operating shortages for the benefit of BPA's firm power customers and available to BPA from rights to interrupt, curtail, or otherwise withdraw, as provided by specific contract provisions, portions of the electric power supplied to customers. Id. Do you agree?

A. No, not with the statement as presented. At most, we may agree that surplus market sales provide operating reserves. Almost all of BPA's surplus sales are sales of secondary energy. For the reasons stated above, we cannot agree that surplus market sales provide planning reserves. BPA has sold some firm surplus, but the terms of the sales are such that they provide little planning reserve benefits.

Q. The IOUs argue that reserves include BPA's rights to interrupt, curtail or otherwise withdraw sales of surplus power when necessary. LaBolle, et al., WP-07-E-JP6-08 at 37. The IOUs note that BPA sells surplus energy in the real-time, day-ahead, balance-of-month and forward electricity markets, controlling the duration of those sales so that BPA can withdraw power from the wholesale market when needed for its regional firm power customers. Id. The IOUs argue BPA's wholesale market surplus sales thus benefit, and avoid service and cost risks to, BPA's utility firm power loads in the region. Id. Do you agree?

A. No. Once again, at most these sales provide operational benefits, not planning benefits. The ability to withdraw the sales from the market is limited to the term of the availability of the power supply supporting the surplus sales. Because almost all of BPA's surplus sales are from secondary energy, there is no long-term benefit from the withdrawal of the sales, and there is no planning benefit from the ability to withdraw the sales from the market. Secondary energy is by its nature a power supply that cannot be known to be available until BPA is within the operating year and can observe precipitation. There are no planning benefits from such a power supply.

Q. The IOUs argue that BPA may establish rights to interrupt, curtail or withdraw power through contractual recall provisions or through power sales for limited terms (e.g., hour-ahead, hourly, day-ahead, balance-of-week, balance-of-month, *monthly and seasonal). LaBolle, et al., WP-07-E-JP6-08 at 37. The IOUs argue this ensures that such BPA surplus power sales benefit and do not pose service and cost risks to BPA's firm power load in the region under sections 5(b), 5(c) and 5(d) of the Northwest Power Act. Id. Do you agree?*

A. Yes. As the IOUs point out, the ability to establish recall rights is for "limited terms."

Q. The IOUs argue that BPA's testimony in the WP-07 rate proceeding confirms that BPA's surplus sales in the wholesale market, such as those under the FPS-07 rate schedule, are made under the Northwest Power Act and constitute reserves (and provide reserve benefits) as contemplated by the Northwest Power Act and its legislative history. LaBolle, et al., WP-07-E-JP6-08 at 37-39. Do you agree?

A. It is possible to construe surplus power as providing some type of reserves. However, the important question is whether the reserves provided by surplus power meet the requirements of reserves as the term is used for purposes of the section 7(b)(2) rate test. The proposed Implementation Methodology instructs us they do not. *See* Implementation Methodology, WP-07-E-BPA-50, Attachment B, at IM-9. However, because the proposed Implementation Methodology is conformed to the Legal Interpretation, we must wait to see what the final Legal Interpretation provides as to whether these reserves meet the intent of section 7(b)(2)(E). Whether BPA's surplus sales comprise reserves as contemplated by the Northwest Power Act and its legislative history is a legal issue. BPA will address parties' properly raised legal issues in the Draft and Final Records of Decision.

Q. The IOUs argue that there are other BPA power sales that should constitute reserves for purposes of the section 7(b)(2) rate test. LaBolle, et al., WP-07-E-JP6-08 at 39-40. The IOUs state that prior to May 8, 2007, sales under the WSPP Agreement Schedule C agreement expressly permitted interruptions for *reasons other than reliability, including "to meet [the] Seller's public utility or statutory obligations to its customers." Id. The WSPP filed a revision to the WSPP Agreement Schedule C agreement on March 9, 2007, to allow interruptions only for reasons of reliability of service to native load. Id. FERC approved WSPP's proposed revision effective May 8, 2007. Id. BPA sold the following amounts of power under WSPP Agreement Schedule C during each fiscal year during the period FY2002 through May 7, 2007:*

	Secondary Sales WSPP Agreement Schedule C	Revenue
FY2002	3,768 aMW	$816,418,000
FY2003	2,907 aMW	$843,059,000
FY2004	2,101 aMW	$650,806,000
FY2005	2,018 aMW	$780,698,000
FY2006	2,762 aMW	$981,493,000
FY2007	630 aMW	$222,509,000

Prior to May 8, 2007, the WSPP Agreement Schedule C specifically provided BPA the ability to interrupt power deliveries to meet BPA's public utility or statutory obligations to its customers. Id. Therefore, BPA's sales under WSPP Agreement Schedule C clearly provided reserves to BPA. Id. Do you agree?

A. Yes. This is consistent with our previous statement that surplus sales provide operating reserves.

Q. The IOUs argue that any BPA rights to interrupt, curtail, or otherwise withdraw power deliveries to outside the region provide reserves. LaBolle, et al., WP-07-E-JP6-08 at 41. Do you agree?

A. The term "reserves" is used in a number of different ways and for different purposes in a variety of contexts. The term "reserves" used in section 7(b)(2)(E) of the Northwest Power Act has a specific meaning and usage that may or may not conform to the use of the same word in other contexts. The important question is not whether a particular citation or quotation might portray something it calls "reserves." The important question is how the rate test is to be performed giving full weight to the term "reserves" as Congress intended it to be used in conducting the section 7(b)(2) rate test. BPA's proposed Legal Interpretation has put forth a definition of "reserves" and an interpretation of how the term should be used under section 7(b)(2)(E). The proposed Implementation Methodology relies on the Legal Interpretation to instruct us how to structure the rate test given this interpretation.

Q. *The IOUs note that BPA has contracts for power sales outside the region. LaBolle, et al., WP-07-E-JP6-08 at 41. The IOUs argue that BPA should recognize that any rights to interrupt, curtail, or otherwise withdraw power deliveries to outside the region provide reserves. Id. Do you agree?*

A. In the context of the 7(b)(2) rate test, no. The rate test does not contemplate that any and all reserves be reflected in the rate test, only those meeting the statutory direction of "…reserve benefits as a result of the Administrator's actions under this chapter… ." The proposed Legal Interpretation has defined this statutory direction. The proposed Implementation Methodology is based on the proposed Legal Interpretation. The proposed Implementation Methodology does not allow us to use "power sales outside the region" in a way that meets the provision of reserves for use in the 7(b)(2) rate test. BPA will address parties' properly raised legal issues in the Draft and Final Records of Decision.

Q. *The IOUs state that the Supplemental Proposal does not recognize any rights to interrupt, curtail, or otherwise withdraw power deliveries to outside the region to provide reserves. LaBolle, et al., WP-07-E-JP6-08 at 41. Do you agree?*

A. Yes.

Q. The IOUs argue that BPA has recalled power under contracts to serve its firm loads. LaBolle, et al., WP-07-E-JP6-08 at 42. BPA has exercised recall rights under contracts and has not renewed surplus sales in the wholesale power market when the power was needed to serve BPA's firm loads. Id. Do you agree?

A. Yes.

Q. The IOUs argue that BPA has not lost reserve benefits due to the diminishment of DSI load. LaBolle, et al., WP-07-E-JP6-08 at 43. The IOUs note that this linear trend indicates that the amount of BPA surplus sales has trended up during the period, while the amount of BPA DSI sales has trended down. Id. These trends are consistent with BPA's surplus sales tending to replace DSI sales during the period. Id. Do you agree?

A. No. We do not agree that BPA's surplus sales are "tending to replace DSI sales during the period." Simply because two things occur at the same time does not mean one is a causal factor of the other. DSI sales are firm power sales. Surplus sales are almost entirely secondary sales. Firm power is not the same as secondary power. If the IOUs had also included sales to preference customers, they would have discovered an upward trend as well. Sales to preference customers are firm power sales. It is much more likely that sales to preference customers have replaced the sales to DSIs, as they are both sales of firm power. Also, the diminishment of sales to the DSIs has other causal factors, including BPA's marketing decisions and DSI business operating decisions, not whether secondary power was being sold by BPA. Further, it is our understanding that the increase in surplus sales is driven more by the supply of secondary power than the diminishment of sales to the DSIs. The increase in the supply of secondary power is a result of the increased requirements of fish operations on the river, resulting in less firm power generation and more secondary power generation. Therefore, the IOUs' claim that surplus sales are replacing DSI sales is more a matter of coincidence of timing than causality. Surplus sales are not a replacement for DSI sales.

Q. The IOUs argue BPA is no worse off today in terms of reserves because of the diminishment of DSI load. LaBolle, et al., WP-07-E-JP6-08 at 44. In fact, the reserve benefits available to BPA from its surplus power sales in the wholesale power market are superior in several respects to those it previously received from its sales to DSIs. Id. For example, the DSI reserves provided recall or interruption rights only for specified portions of the power sales to the DSIs and only for specified purposes and durations. Id. By contrast, BPA has much more flexibility in its wholesale market surplus sales to establish withdrawal or recall rights through limitation of the term of the sale and otherwise. Id. Do you agree?

A. We agree that in theory the recall rights provided by surplus sales could be superior to the recall rights provided by sales to the DSIs if it were our practice to write surplus sales contracts with total recall provisions.

Q. The IOUs argue that the amount (or value) of reserve benefits provided by (i) BPA's secondary energy and (ii) BPA's rights to withdraw power sales is conservatively valued at $120.3 million by use of BPA's operating reserve rate for its transmission customers. LaBolle, et al., WP-07-E-JP6-08 at 45. Do you agree?

A. Assuming, *arguendo*, that surplus sales provide the type of reserves that meet the statutory direction provided in section 7(b)(2)(E), we would need to determine the value of the reserves being provided in the Program Case in order to compute the difference in costs from the 7(b)(2) Case. In doing so, we would seek the least costly source of reserves in the 7(b)(2) Case. Given the assumption that surplus power supplied reserves, we would note that the same amount of surplus sales is available in the 7(b)(2) Case as in the Program Case. Therefore, the least costly source of reserves in the 7(b)(2) Case likely would be the same surplus sales used in the Program Case. These reserves would have the same cost in both Cases, leading to no cost adjustment between the Cases. This difference is not true of reserves supplied by DSIs. If displaceable DSI loads supplied reserves in the Program Case, the same would not be true in the 7(b)(2) Case because there are no displaceable DSI loads in the 7(b)(2) Case. Any within or adjacent DSI load served by the Administrator in the Program Case would become firm COU load in the 7(b)(2) Case. Therefore, a cost differential between the two Cases can arise due to reserves being supplied by DSI power sales.

Q. CUB states reserve benefits are not limited to DSI sales and quotes the Northwest Power Act, which states DSI sales provide "a portion of the Administrator's reserves for firm power loads within the region." 16 U.S.C. 839c(d)(1)(A). Jenks, WP-07-E-CU-1 at 2. Do you agree?

A. Yes. The proposed Implementation Methodology does not limit the source of reserves to DSIs.

Q. CUB cites the Senate report to note that the purpose of reserves under the Act is "to protect firm loads for any reason, including low or critical streamflow . . . unexpectedly poor performance of regional generating resources or conservation measures, and against unanticipated growth of regional firm loads." Jenks, WP-07-E-CU-1 at 2. Is this an accurate quote in the context that CUB is using it?

A. No. The quotation from the Senate report that CUB cites has been edited from the original. CUB is using the quotation to express the purpose of reserves. However, the context in which CUB is using the quotation is to support its contention that reserves are not limited to being provided by DSIs. As we have stated, we agree with CUB's position. However, it should be noted that the full quotation cited by CUB relates specifically to the reserves being provided by DSIs. It does not mention reserves from other sources. The full quotation is included here.

> The power quality provided the direct-service industries is determined by the reserve obligations set forth in their contracts in order to protect service to firm loads of the Administrator. It is intended that these contracts at least provide peaking power reserves similar to those provided in the present contracts, and that the energy reserves shall include a reserve approximately equal to 25 percent of the direct service industrial load to protect firm loads for any reason, including low or critical streamflow conditions, and an additional energy reserve of approximately the same amount to protect firm loads against the delayed completion or unexpectedly poor performance of regional generating resources or conservation measures, and against the unanticipated growth of regional firm loads. One intended result of these procedures is that there will be no increase in firm power commitments to the direct service industrial customers, except for technological improvements purposes.

S. Rep. No. 96-272, 96th Cong., 1st Sess. 28 (1979).

Q. *CUB quotes a BPA press release and the BPA Journal to argue there are other resources that fit the definition of reserves because BPA uses surplus power sales to protect firm loads if harsh weather or low water conditions give rise to excess firm loads. Jenks, WP-07-E-CU-1 at 2. Do you agree?*

A. As noted previously, the term "reserves" is used in a number of different ways and for different purposes in a variety of contexts. Finding a quotation in a press release or article that uses the term "reserves" and transporting that quotation into the context of the section 7(b)(2) rate test is not compelling. The term "reserves" used in section 7(b)(2)(E) has a specific meaning and usage that may or may not conform to the use of the same word in other contexts. The important question is not how a BPA Journal article might portray something it calls "reserves." The important question is how the rate test is to be performed giving full weight to the term "reserves" as Congress intended it to be used in conducting the section 7(b)(2) rate test. BPA's proposed Legal Interpretation has put forth a definition of "reserves" and an interpretation of how section 7(b)(2)(E) intends the term to be used. The proposed Implementation Methodology relies on the Legal Interpretation to instruct BPA as to how to structure the rate test given this interpretation.

Q. CUB argues that by controlling the terms of a contract, BPA can structure the contract so that surplus sales are available as a reserve resource for firm sales; for example, BPA can retain surplus power until it is not needed for firm load, then sell it in the hour ahead, day ahead, or balance of week markets. Jenks, WP-07-E-CU-1 at 3. Do you agree?

A. It is possible to construe surplus power as providing reserves. However, the important question is whether the reserves provided by surplus power meet the requirements of reserves as the term is used in section 7(b)(2)(E). The proposed Implementation Methodology instructs us that they do not. However, because the proposed Implementation Methodology is conformed to the Legal Interpretation, we will wait to see what the final Legal Interpretation instructs us as to whether these reserves meet the intent of section 7(b)(2)(E).

Q. Quoting section 3(17) of the Northwest Power Act, CUB argues that counting surplus sales would be consistent with the Act because surplus power is available to the Administrator to avert operating shortages for the benefit of firm power customers. Jenks, WP-07-E-CU-1 at 3-4. Do you agree?

A. We will not address the legal argument CUB raises. However, as noted previously, it is possible to construe surplus power as providing reserves. The important question is whether the reserves provided by surplus power meet the requirements of reserves as the term is used in section 7(b)(2)(E).

Q. *CUB notes that there is now a power market and parties no longer need to use bilateral contracts to sell excess generation that would often contain recall or interruption provisions. Jenks, WP-07-E-CU-1 at 4. CUB argues BPA no longer needs to rely on such contracts and BPA can get even greater flexibility by selling surplus power under short-term contracts and by having a large volume of power in reserve. Id. Do you agree?*

A. It is possible to construe surplus power as providing reserves. However, the important question is whether the reserves provided by surplus power meet the requirements of reserves as the term is used in section 7(b)(2)(E).

Q. *CUB states surplus sales are significant today and in every year since 1997, the amount of surplus sales revenue has exceeded DSI sales revenue and since 1997, surplus revenue has averaged $771 million while DSI revenue averaged $190 million. Jenks, WP-07-E-CU-1 at 5. Do you agree?*

A. We agree that surplus sales are significant. We do not agree that BPA's revenues from surplus sales are an indication of the amount of surplus sales that could arguably be considered as reserves in the context of the rate test. Revenues cannot supply the type of reserves considered in the rate test. Rather, it is the amount of power that should be considered.

Q. *Was BPA making surplus sales prior to December 5, 1980?*

A. Yes. BPA has been making surplus sales since at least 1939. BPA's average nonfirm (*i.e.*, surplus) rate beginning September 18, 1939, was 2.5 mills per kilowatt-hour. This number was calculated by dividing actual revenues received under the H-1 rate schedule, the Nonfirm Energy Rate Schedule at that time, by the energy sold under that rate schedule. *See* Wholesale Power and Transmission Rate Projections 1992-2013 and Historical Wholesale Power Rates 1939-1991, document number BP/DOE-2032, published December 1992, page A-28. The history of the nonfirm rates shows that BPA sold surplus power for every rate period between 1939 and 1991, the end date of that study.

Section 12: Applicable 7(g) Costs

Q. The IOUs argue that BPA should subtract Applicable 7(g) Costs from the Program Case costs but include Applicable 7(g) Costs in the 7(b)(2) Case costs. LaBolle, et al., WP-07-E-JP6-08 at 26. The IOUs argue that if BPA properly includes Applicable 7(g) Costs in the 7(b)(2) Case costs, it is particularly important that the Applicable 7(g) Costs, such as the costs of uncontrollable events, be properly determined for the purpose of such inclusion. Id. Do you agree?

A. We agree that the cost of uncontrollable events, as an Applicable 7(g) Cost for purposes of the 7(b)(2) rate test, should be excluded from the Program Case rates when performing the 7(b)(2) rate test. However, contrary to the IOUs' argument that Applicable 7(g) Costs should be included in the 7(b)(2) Case, we have relied on the plain language in the proposed Implementation Methodology, which states that Applicable 7(g) Costs will be removed from both the Program and 7(b)(2) Cases. In any event, BPA has not identified any costs as being costs of uncontrollable events in this rate case.

Q. Please describe how Applicable 7(g) Costs are removed from the Program Case PF rate.

A. Section IV.6 of the Implementation Methodology describes the removal of applicable 7(g) costs from the Program Case:

> 6. Subtracting Applicable 7(g) Costs
>
> Prior to comparing the Program Case rates to the 7(b)(2) Case rates, section 7(b)(2) directs that the Applicable 7(g) Costs are to be subtracted from the Program Case rate. To accomplish this, the

> amounts of Applicable 7(g) Costs allocated to the 7(b) rate pool will be removed from the Program Case rates. To do so, the allocated Applicable 7(g) Costs will be expressed as a unit rate comparable to the 7(b) rate and will be subtracted from the annual 7(b) rates to calculate the adjusted Program Case rates.

Implementation Methodology, WP-07-E-BPA-50, Attachment B at IM-6. Thus, Applicable 7(g) Costs are removed from the Program Case PF rate after that rate has been calculated.

Q. *Please describe how Applicable 7(g) Costs are removed from the 7(b)(2) Case PF rate.*

A. Section V.4 of the Implementation Methodology describes the removal of applicable 7(g) costs from the 7(b)(2) Case:

> 4. Revenue Requirement
>
> Except for specific exclusions resulting from the Five Assumptions, the revenue requirement for the 7(b)(2) Case will be the same as the Program Case. The specific exceptions are:
>
> 1) all costs related to the Residential Exchange Program will be removed, including the identified BPA costs of implementing the program. Any costs included in the Program Case that are the result of a settlement of Residential Exchange Program claims will also be excluded;
>
> 2) all costs of any acquisition of new resources will be removed;
>
> *3) Applicable 7(g) Costs will be removed, that is, the costs of conservation, billing credits, experimental resources and uncontrollable events.*
>
> In addition to these explicit exclusions, the secondary effects of their exclusion will be considered. Specifically, the Program Case repayment study will be performed without the excluded costs to determine the interest and amortization applicable to the 7(b)(2) Case.

Implementation Methodology, WP-07-E-BPA-50, Attachment B at IM-8. (Emphasis added.) As described above, Applicable 7(g) Costs are removed from the 7(b)(2) Case revenue requirement before the PF rate is calculated.

Q. The OPUC notes that BPA proposes to subtract Applicable 7(g) Costs from both the Program Case and the 7(b)(2) Case for purposes of comparing the two cases for the 7(b)(2) rate test. Hellman and McGovern, WP-07-E-PU-1 at 21. The OPUC argues this is a change in policy because a review of the Administrator's 1984 Section 7(b)(2) Implementation Methodology Record of Decision and his 1984 Legal Interpretation of Section 7(b)(2) reflects that BPA previously concluded that Applicable 7(g) Costs should only be subtracted from the Program Case. Id. Do you agree with OPUC's contention that this constitutes a change in BPA policy if not practice?

A. Although BPA's proposal to subtract Applicable 7(g) Costs from both the Program Case and the 7(b)(2) Case for purposes of comparing the two Cases for the 7(b)(2) rate test is a change, it is not a material change in that the only Applicable 7(g) Costs affected are those associated with the cost of uncontrollable events and experimental resources. These costs have always been forecast to be zero and removing a zero cost from the 7(b)(2) Case will not have a material effect on the 7(b)(2) rate test results. In addition, it appears that OPUC misunderstands the context of the cited passage of the 1984 Implementation Methodology. The 1984 Implementation Methodology states:

> "The projected amounts to be charged" means the program case. "Exclusive of amounts charged … under section 7(g)" means that the enumerated section 7(g) costs are to be subtracted from the program case. There is no parallel command in the statute to subtract from the 7(b)(2) case the costs corresponding to those allocated under section 7(g) in the program case. The result, in a numerical display, would be as follows:
>
> 20 mills (“the projected amount to be charged”; also called the program case amount)
> - 3 mills (certain 7(g) charges)
> 17 mills (the amount to be compared with the 7(b)(2) case amount; also called the net program case amount)

> This amount, 17 mills, is to be compared to the 7(b)(2) case amount. For illustrative purposes, assume that the 7(b)(2) case amount is 15 mills, which may include costs that correspond to those allocated under section 7(g) in the program case. The program case amount is therefore 2 mills greater than the 7(b)(2) case amount (17 mills - 15 mills = 2 mills). The test has thus triggered.

Section 7(b)(2) Implementation Methodology ROD, August 1984, b-2-84-F-02 at 4-5.

As the quotation demonstrates, the 1984 ROD was speaking of the specific calculation of the subtraction before the calculation of rates. The 1984 ROD uses an example of a 20 mill Program Case rate, a subtraction of 3 mills for Applicable 7(g) Costs, and a resultant Program Case rate of 17 mills. The 1984 ROD then assumes a 7(b)(2) Case rate of 15 mills. It is at this point that the ROD is saying that there is no subtraction of Applicable 7(g) Costs from this 7(b)(2) Case rate because the cost of conservation resources may be included in the rate. The 15 mill 7(b)(2) Case rate is compared to the 17 mill Program Case rate, and the rate test has triggered by 2 mills.

BPA continues to follow the practice that conservation and billing credit costs may be in the 7(b)(2) Case rate. The issue raised by OPUC is whether there are actions that affect the calculation of the 7(b)(2) Case rate, the 15 mills in the example, prior to the rate test comparison. It is here that BPA has offered clarifying language to document the removing of Applicable 7(g) Costs from the 7(b)(2) Case revenue requirement before the calculation of the 7(b)(2) Case rate. BPA added the instruction of removing the Applicable 7(g) Costs from the 7(b)(2) Case revenue requirement to present a more complete picture of how the 7(b)(2) Case rate computations should be performed.

Q. The OPUC argues that it is possible that Applicable 7(g) Costs will be double-counted in the 7(b)(2) Case under the 1984 7(b)(2) Methodology. Hellman and McGovern, WP-07-E-PU-1 at 23. The OPUC notes the Administrator specifically addressed this possibility in the 1984 Implementation ROD, and noted the possibility that Applicable 7(g) Costs could be double-counted. Do you agree?

A. BPA's clarification in the proposed Implementation Methodology does not materially change the 1984 Implementation Methodology on this question.

> Double counting of all or some of the section 7(g) costs (conservation; resource and conservation credits ("billing credits"); experimental resources; and uncontrollable events) may be theoretically possible, as explained above. However, it does not occur in all instances. The costs of both experimental resources and uncontrollable events are included in total in both the program case amount (20 mills, in the example given above) and in the 15 mill 7(b)(2) case amount. But the costs of billing credits and conservation, although appearing in the 20 mill figure, are not necessarily included in the 15 mills. This is because billing credits and programmatic conservation are added to the resources used to serve the 7(b)(2) customers only to the extent that they are needed after the FBS is exhausted and only in the event that they are the least-cost resources to be added. If the FBS is sufficient to serve the 7(b)(2) load, or other available additional resources have lower costs, then billing credits and programmatic conservation will not be added to the 7(b)(2) case.

Section 7(b)(2) Implementation Methodology ROD, August 1984, b-2-84-F-02 at 5.

As the foregoing text shows, conservation and billing credit costs are added to the 7(b)(2) Case only to the extent they are needed after the FBS is exhausted and only in the event that they are the least-cost resources to be added. Adding the costs to the 7(b)(2) Case under these circumstances presupposes that they have already been removed. Therefore, BPA's historical treatment and the proposed Implementation Methodology treatment of conservation costs are in harmony with the1984 ROD on this issue.

We do not agree with the OPUC's concern that applicable 7(g) costs can be double-counted in the 7(b)(2) Case. The costs of uncontrollable events and the costs of experimental resources have always been zero. The cost of conservation and billing credits are removed from the 7(b)(2) Case revenue requirement. Therefore, if no applicable 7(g) costs are included in the 7(b)(2) Case before conservation resources may or may not be added, no exposure to double counting is evident.

Q. The OPUC argues that the practical effect of this alleged change in the 7(b)(2) Methodology is to disadvantage the Program Case and thereby potential REP benefits. Hellman and McGovern, WP-07-E-PU-1 at 23. Even though it may seem at first glance that subtracting Applicable 7(g) Costs from both the Program and 7(b)(2) Cases simply neutralizes the costs, subtracting the costs from both cases causes the average rate for the 7(b)(2) Case to decrease more than the average rate for the Program Case. Id. This occurs because the 7(b)(2) loads are smaller than the Program Case loads. Id. Do you agree?

A. Although we agree that the rate effect of the removal of Applicable 7(g) Costs has disparate effects on the two cases, we do not agree that this has the practical effect of disadvantaging the Program Case. Rather, there is no material difference between the 1984 Implementation Methodology and the proposed Implementation Methodology.

Q. The OPUC argues that BPA's alleged change in methodology is not supported by the language of the Act. Hellman and McGovern, WP-07-E-PU-1 at 24. As noted in the Administrator's 1984 Legal Interpretation, Congress specifically stated that Applicable 7(g) Costs should be excluded from the Program Case, but did not *include a similar directive for the 7(b)(2) Case. See Legal Interpretation of Section 7(b)(2) at 12. Id. To give these words any meaning, the cost must be excluded from the Program Case only. Id. Do you agree?*

A. No, for the reasons explained previously. We relied upon the proposed Legal Interpretation to construct the proposed Implementation Methodology, just as the 1984 Legal Interpretation was relied upon to construct the 1984 Implementation Methodology. We believe that the proposed Implementation Methodology is consistent with the interpretation of the language of the Northwest Power Act and the proposed Legal Interpretation. BPA will address parties' properly raised legal issues in the Draft and Final Records of Decision.

Section 13: Applicable 7(g) Costs – Uncontrollable Events

Q. Please define "uncontrollable events."

A. The term "Uncontrollable Event" is defined in the proposed Implementation Methodology:

> <u>Uncontrollable Event</u>: A discrete event which differs from the continuum of changing events that occur in nature, business and government (such as changes in water conditions, aluminum prices, and electricity markets) and that are routinely reflected in ratemaking.

Implementation Methodology, WP-07-E-BPA-50, Attachment B, at IM-2.

Q. The IOUs note that BPA has never subtracted any costs of uncontrollable events from the Program Case costs – and BPA has been performing the section 7(b)(2) rate test for the entire period since January 1, 1985, when the rate test first became applicable. LaBolle, et al., WP-07-E-JP6-08 at 26. The IOUs argue that, given the magnitude of BPA's activities and BPA's exposure to uncontrollable events, the absence of any costs of an uncontrollable event during this period *demonstrates that BPA is applying unduly restrictive criteria when determining the costs of uncontrollable events for the purposes of conducting the section 7(b)(2) rate test. Id. Do you agree?*

A. No. The term "uncontrollable events," if taken literally, would encompass millions of events and would make little sense in the context of the section 7(b)(2) rate test. There are millions of "events" that occur daily and which are beyond BPA's control. It is impossible to identify each event that has occurred and which might have some impact on BPA's costs. As noted previously, the section 7(b)(2) rate test compares PF rates for preference customers under two scenarios: with and without the specific assumptions of section 7(b)(2). This suggests that the comparison is between rates that share the same basic costs but for the specific exceptions. For this reason, uncontrollable events should not exclude costs from the Program Case that are due to conditions that simply vary over time and are typically reflected in rates. Also for this reason, as noted in the Implementation Methodology, uncontrollable events are not properly viewed as all conceivable events beyond BPA's control, but rather the discrete and significant events beyond BPA's control that differ from the continuum of changing conditions that occur in nature, business and government and are routinely reflected in rate development. Thus, it is not surprising that BPA has not previously identified an uncontrollable event. This, however, does not mean that BPA's definition is too restrictive. In contrast, the IOUs' proposed definition would be too broad. If nearly all events are uncontrollable events, excluding such costs from the Program Case would prevent the 7(b)(2) rate test from ever finding that the Program Case rates exceed the 7(b)(2) Case rates.

Q. The IOUs argue that BPA's costs of the terminated WNP-1 and WNP-3 plants are costs of uncontrollable events and these costs should be subtracted from the

Program Case as Applicable 7(g) Costs of uncontrollable events. LaBolle, et al., WP-07-E-JP6-08 at 27. The IOUs argue that the fact BPA made a measured, rational response to these uncontrollable events does not render the events controllable. Id. The IOUs argue that BPA's costs of terminated WNP-1 and WNP-3 are the costs of an uncontrollable event because the Supply System was unable to issue bonds to finance completion of WNP-l and WNP-3, and they were subsequently terminated without being completed or producing power. Id. The Supply System's inability to issue bonds was an uncontrollable event. Id. BPA's costs with respect to WNP-1 and WNP-3, from which BPA received no power, are costs of "uncontrollable events." Do you agree?

A. No. The termination of WNP-1 and WNP-3 was based on a reasoned process of deliberation leading to the discretionary termination of a generating facility. This is not an uncontrollable event. BPA previously issued a ROD regarding the termination of WNP-1 and WNP-3 ("WNP-1 and WNP-3 ROD"). In that ROD, BPA conducted a thorough analysis of numerous factors relating to the discretionary decision of whether the plants should be terminated. *Id*. BPA listed a number of decision factors. *Id*. at 6. These factors included how completing WNP-1 and WNP-3 would affect BPA's competitiveness, *id.* at 6-7; BPA's need for additional resources, *id*. at 7-8; how WNP-1 and WNP-3 compare to BPA's other resource alternatives, *id*. at 8-10; and the advantages and risks of WNP-1 and WNP–3 and their alternatives, *id*. at 11-13. BPA also reviewed the alternate uses of WNP-1 and WNP–3. *Id*. at 13-14. In summary, the Administrator stated:

> On balance, it is my determination that based on the totality of factors, on the assumptions regarding the future of the plants, and on other circumstances, neither the long-term continued preservation of WNP-1 and -3 or the ultimate completion of the projects under the terms of the existing agreements is in the best interest of BPA and the region's ratepayers. Consistent with this

> determination, I find that the plants are not capable of producing energy consistent with prudent utility practice.

Id. at 14. The decision to terminate WNP-1 and WNP–3 was a carefully reasoned discretionary decision in which the Administrator explained the reasons for that decision. A decision of this nature is not an uncontrollable event. Indeed, this decision would be best characterized as a controllable event: a discretionary decision made by the Administrator.

Furthermore, even if we accept that the termination of WNP-1 and WNP-3 were uncontrollable events, we would have to determine which costs were due to uncontrollable events and which were not. Clearly not all of the costs of WNP-1 and WNP-3 are due to uncontrollable events. The debt service costs were incurred as a result of the decision to build the projects; such decision cannot be considered an uncontrollable event, even under the IOUs' definition. Therefore, the only costs that would possibly qualify as uncontrollable event costs under the IOUs' definition would be the costs of termination. In this Supplemental Proposal, the WNP-1 and WNP-3 decommissioning costs are projected to be $200,000 in FY 2009.

Q. The IOUs argue that BPA has previously recognized that the costs of terminated generating facilities, such as WNP-l and WNP-3, are the costs of uncontrollable events for purposes of section 7(g) of the Northwest Power Act. LaBolle, et al., WP-07-E-JP6-08 at 29-30. The IOUs state that the initial long-term power sales contracts under the Northwest Power Act entered into by BPA with utilities in the region recognized that BPA's costs of uncontrollable events to be allocated under section 7(g) of the Northwest Power Act include costs of a "terminated generating facility." Id. Please respond.

A. The IOUs refer to section 8(j) of the 1981 General Contract Provisions (GCPs) entitled "Allocation of certain section 7(g) Costs," which falls under section 8 of the GCPs, entitled "Equitable Adjustment of Rates." Most of BPA's power sales contracts executed in 1981 included the GCPs as an exhibit. The 1981 power sales contracts terminated on July 1, 2001. This date precedes the effective date of BPA's 2007 wholesale power rates, which went go into effect on October 1, 2006. Section 8 of the GCPs, including section 8(j), governed only the development of rates that were to be in effect during the term of the 1981 power sales contracts, that is, the rates that would apply to the sales made under those contracts. Those sales terminated on July 1, 2001. The rates being developed in this proceeding will not be in effect during the term of the 1981 contracts, and section 8 of the GCPs does not apply.

Furthermore, section 8(j) did not establish that all terminated generating facility costs are costs of uncontrollable events. GCP section 8(j) states:

> (j) Allocation of Certain Section 7(g) Costs. Costs of uncontrollable events, including but not limited to costs of a terminated generating facility and costs of experimental resources, in excess of the cost of cost effective resources, shall be allocated pursuant to section 7(g) of PL-96-501 and shall be allocated among Customers on a uniform per kW or kWh basis…

The quoted language refers to "*[c]osts of uncontrollable events*, including but not limited to costs of a terminated generating facility…" The first requirement of this provision is that the event be an "uncontrollable event." BPA does not dispute that, during the time when this provision was actually in effect, it was possible for the costs of a terminated generating facility to be included in the costs of an uncontrollable event. This would occur where the termination of the facility was a result of an uncontrollable event. This requires review of the particular terminated generating facility to determine if its termination was a reasoned discretionary decision or if it was the result of an uncontrollable event, such as an earthquake, a flood, a terrorist act, and so on.

The termination of a generating facility that is the result of a reasoned decision-making process that has taken place over a period of time, and where the decision could have been decided either way, cannot be considered an uncontrollable event. In deciding whether to terminate a generating facility, the owner must receive and analyze information about many factors relating to termination. How much would it cost? Is there a market for the power above cost? What would be the decommissioning costs? These many questions must be weighed by the decision-maker. The decision that is informed by such analyses where there is not a required termination, but rather a discretionary decision to do so, is not uncontrollable. Uncontrollable events can cause the termination of a generating facility. The termination of a generating facility, however, is not an uncontrollable event unless the termination is caused by an uncontrollable event.

Q. The IOUs describe BPA's Starting Financial Reserves Available for Risk. LaBolle, et al., WP-07-E-JP6-08 at 30. The IOUs note that in the absence of the risk of uncontrollable events that give rise to the need for Starting Financial Reserves Available for Risk, BPA's revenue requirement during the rate period would be lower by an expected value amount equal to the Starting Financial Reserves Available for Risk of $1,031 million. Id. The IOUs argue that Starting Financial Reserves Available for Risk are costs due to the uncontrollable events for which BPA maintains such reserves. Id. Hence, the IOUs argue such costs must be subtracted from the Program Case as Applicable 7(g) Costs. Id. Do you agree?

A. No. First, the IOUs are equating an asset with a cost. BPA's financial reserves primarily consist of cash in the BPA Fund at the U.S. Treasury. Cash on hand is an asset. We do not understand how an asset can become a cost. Furthermore, if the risks were not present, as the IOUs posit, BPA's revenue requirement would not be lower by $1,031 million. BPA's rates are set to recover costs. Revenues from rates must be adequate to demonstrate cost recovery, not just in the rate period, but for the entire cost recovery period that extends for another 50 years. If we were to lower rates to recover $1 billion less revenue, we could not demonstrate cost recovery to FERC over the entire cost recovery period. Because the cost recovery period extends for 50 years, lowering rates by $1 billion would result in a $50 billion under-recovery over the cost recovery period. We believe this might be noticed by FERC, resulting in the rejection of the rate proposal.

Second, the IOUs argue that normal utility business risk constitutes an "uncontrollable event" for purposes of the 7(b)(2) rate test. In the same way that Planned Net Revenues for Risk (PNRR) have been used to mitigate normal utility uncertainty by increasing the availability of financial reserves, a sufficient amount of starting financial reserves can mitigate the need to include PNRR costs in rate base. In either case, cash over-and-above the normal or average condition forecasted need for cash will exist in the event something other than normal or average conditions actually occur.

We believe it is simply a normal utility risk when actual conditions that are part of a continuum of possible conditions depart from the normal or average conditions forecasted in a rate proceeding. Such departures from the forecasted average themselves or the business decisions brought on by these departures do not rise to the level of "uncontrollable events."

Q. What are Planned Net Revenues for Risk?

A. PNRR is the amount necessary, together with Cost Recovery Adjustment Clause and other measures, to mitigate the wide uncertainties BPA faces to achieve its

Treasury Payment Probability standard. PNRR, however, is only one component of the total cash flow for risk.

Q. *Has BPA previously defined what is included in the "wide uncertainties" mitigated by PNRR?*

A. Yes. BPA has previously defined the range of uncertainties to include operating risk – Hydro and thermal generation performance, California market prices, Southwest gas prices, and generating and non-generating public utility load uncertainty. As a counterpart to RiskMod, the Non-Operating Risk Model produces cost distributions that reflect the impact of non-generating risks that Power Services (PS) is facing in the Fiscal Year (FY) 2009 rate period. These non-operating risks include, but are not limited to fish and wildlife operations and maintenance and capital recovery expenses and other expenses. *See* Risk Analysis Study, WP-07-E-BPA-48.

Q. *The IOUs note that PNRR is a component of the revenue requirement often used by BPA to bolster reserves to mitigate the impacts of operating and non-operating risks. LaBolle, et al., WP-07-E-JP6-08 at 32. The IOUs note that the Initial Proposal states that it does not include PNRR. Id. The IOUs argue that if and to the extent BPA includes PNRR, such PNRR should be subtracted from the Program Case costs as costs of uncontrollable events. Id. The IOUs argue the fact that BPA often includes PNRR in its revenue requirements to cover the costs of uncontrollable events does not and cannot force the conclusion that such events are not "uncontrollable events" and that such costs are not the costs of "uncontrollable events." Id. Do you agree?*

A. No. As noted above, PNRR, along with other measures, mitigates the risk of a wide range of uncertainties routinely experienced in ratemaking. The cost of mitigating a wide range of uncertainties is not the same as the cost of uncontrollable events, which are discrete events not routinely reflected in ratemaking. Therefore, PNRR costs are not the costs of uncontrollable events and should not be included in the 7(g) adjustment in the 7(b)(2) rate test calculation.

Section 14: Applicable 7(g) – DSI Benefits

Q. The IOUs note that BPA has executed power sales contracts with each of three aluminum DSIs and their Public Utility Partners and executed a contract to sell power for the Port Townsend Paper Corporation plant, a non-aluminum DSI load. LaBolle, et al., WP-07-E-JP6-08 at 14-17. The IOUs note BPA is providing DSI service benefits to the three aluminum DSI loads in the form of financial payments by "cashing-out," or monetizing, the value of a power sales contract. Id. The DSI ROD recognizes that sales and delivery of physical power or payment of the monetized value of a power contract are alternative means of delivering service benefits to the DSIs, citing the DSI ROD at 2, 18-19. Id. The IOUs argue the Initial Proposal excludes the costs of service benefits to the aluminum DSIs and the sale of 17 aMW of power to Port Townsend Paper Corporation from 7(b)(2) Case costs in the performance of the section 7(b)(2) rate step for the FY 2009 rate period. Id. The IOUs cite BPA's argument for the Initial Proposal's inclusion of DSI monetary service benefit costs in the Program Case and not in the 7(b)(2) Case, which is that in the 7(b)(2) Case there is no customer class with which to enter into such an agreement and there is no logical way to allocate "intra-utility" costs to other public body customers. Id. The IOUs argue that this argument rests on an unsupported premise that DSI benefit costs can be included in the 7(b)(2) Case costs if, and only if, such costs would have actually been incurred by a PF Preference rate customer and such customer *was actually able to allocate those costs to other PF Preference rate customers. Id. LaBolle, et al., WP-07-E-JP6-08 at 23-24. Do you agree?*

A. Although we do not agree that our original premise is unsupported, it is not clear to us now whether this premise is appropriate. We will reconsider this issue based on the complete record and recommend a resolution to the Administrator.

Q. The IOUs note that, in the 7(b)(2) Case, BPA projects the power costs of serving the general requirements (including the costs of serving within and adjacent DSI loads) of PF Preference rate customers. LaBolle, et al., WP-07-E-JP6-08 at 19. However, BPA does not point to any reason or ratemaking logic that would require BPA to assume that BPA is not serving those general requirements. Id. In other words, BPA retains the role of serving the general requirements (including the within and adjacent DSI loads) of PF Preference rate customers in the 7(b)(2) Case. Id. The monetary payments are treated by BPA as an alternate form of delivery of DSI benefits in lieu of sales of power by BPA at IP rates, and the form of delivery of DSI benefits selected by BPA should not increase the section 7(b)(2) trigger amount or reduce the level of REP benefits. Id. Do you agree?

A. Because the DSIs have a monetized power sale, we agree that the monetary payments are an alternate form of delivery in lieu of sales of power by BPA to the aluminum DSIs. We will consider whether the form of delivery of DSI benefits selected by BPA should increase the section 7(b)(2) trigger amount or reduce the level of REP benefits based on the complete record and recommend a resolution to the Administrator.

Q. The IOUs argue that questions of whether a public body customer would enter into a DSI benefit contract or could allocate the costs of such a contract are irrelevant. LaBolle, et al., WP-07-E-JP6-08 at 20. In fact, BPA actually entered *into those contracts – monetized power sales contracts to provide DSI benefits. Id. It is reasonable and appropriate to assume in the 7(b)(2) Case that BPA would enter into the monetized power sales contacts for service to DSI loads that it in fact entered into and to assume that the 7(b)(2) Case PF rate should and would reflect BPA's costs that it incurs under those monetized power sales contacts for service to DSI loads. Id. The form of delivery selected by BPA should not increase the section 7(b)(2) trigger amount or decrease the level of REP benefits. Id. Do you agree?*

A. We are undecided at this point in time. The IOUs raise interesting arguments that we will consider in light of the entire record.

Q. The IOUs argue that even if it were assumed that the DSI financial benefits were being provided by the individual public agency customer, those costs are still part of power costs for the general requirements of the public agency customers and can and should be included in the 7(b)(2) Case costs. LaBolle, et al., WP-07-E-JP6-08 at 20. Do you agree?

A. No. We agree that the DSI financial benefits paid by BPA are a part of the power costs for the general requirements of public agency customers. As stated in the Initial Proposal, we have included the costs of the DSI financial benefits in BPA's revenue requirement and allocated these costs according to section 7(g). We further note that these costs do not appear to be Applicable 7(g) Costs. However, if they DSI financial benefits were paid by the public agency customer, they would not be BPA costs and would not be power costs of the general requirements of public agency customers as defined by section 7(b)(2) and the Implementation Methodology.

Q. The IOUs argue that the three aluminum DSI plants for which BPA provides service benefits pursuant to the three monetized power sales contracts are

Columbia Falls, Ferndale, and Goldendale, which are listed as within or adjacent to BPA preference customers' geographic service territories in Appendix B to the Report of the Senate Committee on Energy and Natural Resources, S. Rep. No. 272, 96th Cong., 1st Sess. (1979), Appendix B at 66. LaBolle, et al., WP-07-E-JP6-08 at 21. Do you agree?

A. Yes.

Q. The IOUs argue that the Port Townsend Paper Corporation plant is within or adjacent to BPA preference customers' geographic service territories because it is in fact being served by a preference customer (Clallam PUD). LaBolle, et al., WP-07-E-JP6-08 at 22. Please respond.

A. It is our understanding that Port Townsend Paper Corp., although physically located inside the service territory of Puget Sound Energy, is electrically interconnected with Clallam PUD. It is our understanding that service is provided to the mill over a sub-transmission line that is partially owned by Clallam and partially by Port Townsend. Therefore, by applying the instructions in the proposed Implementation Methodology, we would determine that Port Townsend Paper is a within or adjacent DSI.

Q. The IOUs argue that monetized DSI service benefits or the use of a BPA power contract to sell surplus power (at the FPS rate) to a preference customer for resale to a DSI should be treated the same as DSI loads in the 7(b)(2) Case. LaBolle, et al., WP-07-E-JP6-08 at 22. Do you agree?

A. BPA will consider this issue based on the complete record.

Q. The IOUs argue that the Initial Proposal's treatment of the costs of service benefits to the aluminum DSIs in the performance of the section 7(b)(2) rate test for the FY 2009 rate period has the effect of reducing REP benefits by an amount almost equal to the DSI monetary benefits, that is, the Initial Proposal's approach *to determining 7(b)(2) Case costs has the practical effect of imposing virtually the entire cost of the DSI service benefits on the PF Exchange rate. LaBolle, et al., WP-07-E-JP6-08 at 23. Do you agree?*

A. No. Our calculations show that approximately 55 percent of the DSI financial benefits are borne by the IOUs through reduced REP benefits. Furthermore, because we are further reducing the REP benefits to account for Lookback amounts, there is no reduction in the proposed REP benefits to the IOUs. The IOUs' proposed treatment of the DSI financial benefits simply allows the IOUs to repay the Lookback Amounts faster.

Q. The IOUs note that BPA staff performed an analysis using Supplemental Proposal RAM model for FY 2009, indicating that (1) the DSI monetary service benefits are equivalent to about 350 aMW of IP load and (ii) if BPA were to provide benefits to the DSIs through sales of 350 aMW under the IP rate in lieu of DSI monetary benefits, the projected REP benefits would increase from $250 million to about $300 million in FY 2009. LaBolle, et al., WP-07-E-JP6-08 at 23-24. The IOUs argue that BPA's decision to provide DSI benefits through monetary payments to DSIs (or through power sales through the local utility) should not reduce the level of REP benefits provided by BPA. Id. Indeed, BPA stated in the DSI ROD that, in order to provide DSI benefits through monetary benefits to DSIs, BPA would need to "be assured that the cost impact on other customers was 'roughly no greater than if BPA had exercised its discretion to serve the DSI customers' directly with physical power deliveries using the IP rate." (DSI ROD at 18-19.) Id. Please respond.

A. We acknowledge that this is a potential way of reflecting DSI benefits in the 7(b)(2) Case and will consider this issue based on the complete record.

Q. The IOUs argue that the costs of the DSI service benefit monetary payments should be included in the 7(b)(2) Case costs. LaBolle, et al., WP-07-E-JP6-08 at 25. Alternatively, the 350 aMW of DSI sales at the IP rate that BPA has concluded is equivalent to its DSI service benefit monetary payments should be included in the general requirements of the PF Preference rate customers in the 7(b)(2) Case. Id. In addition, the 17 aMW sale by BPA for the Port Townsend Paper Corporation load should also be included in the general requirements of the PF Preference rate customers in the 7(b)(2) Case. Id. Please respond.

A. We acknowledge that these are potential ways of reflecting DSI benefits in the 7(b)(2) Case and will consider these alternatives based on the complete record.

Section 15: Slice Surplus Sales

Q. The IOUs note that the Initial Proposal assumes, in performing the section 7(b)(2) rate test, that BPA sells – at market rates – surplus power associated with the Slice product when, in fact, BPA is selling the same power to Slice customers under the Slice rate. LaBolle, et al., WP-07-E-JP6-08 at 46. The IOUs argue that BPA then reverses this assumption after performing the section 7(b)(2) rate step and allocating any section 7(b)(3) reallocation amount. Id. The IOUs argue that BPA has not adequately explained the reasons for making and reversing this assumption and that BPA should explain any necessity for, and the consequences of, any such proposed treatment. Id. Please respond.

A. In the WP-07 Final Proposal, we used only the non-Slice portion (77.37 percent) of the secondary energy produced by the Federal Columbia River Power System (FCRPS) in the calculation of rates. The non-Slice portion is the amount of revenue that BPA forecasts it will earn from the sale of 77.37 percent of the FCRPS secondary energy in the West Coast electric markets. In addition to these sales, the other 22.63 percent of the secondary produced by the FCRPS is sold as a part of the Slice product at the PF Slice rate. In the WP-07 Supplemental, we now propose using revenues as if all of the secondary energy produced by the FCRPS was sold in the electric markets in the calculation of rates in the Rate Design Step ratemaking.

In the Rate Design Step, the PF rate pool includes the firm portion of the Slice product sales. Therefore, it is more proper from a general ratemaking prospective to include the total secondary revenue credit produced by the FCRPS in the rate pool that is paying the costs of the FCRPS at this point in the ratemaking process, the total PF rate pool. After the Rate Design Step, in the Slice Separation Step, the Slice product, costs, loads, and secondary revenue credit are removed from the PF Preference load pool to produce the non-Slice PF Preference rate.

In summary, during the ratemaking steps that establish the unbifurcated PF rate, which includes all firm PF Preference loads and all PF Exchange loads, it is proper to use the full amount of secondary revenue credit. Because the full secondary credit is used in this stage of ratemaking, the unbifurcated PF rate, which will later be bifurcated into the PF Preference and PF Exchange rates if the 7(b)(2) rate test triggers, is lower than it would otherwise be. The IP rate is also lower because it is linked to the lower unbifurcated PF rate at that point in the ratemaking.

The IOUs may assume BPA is receiving a different amount of revenue for the surplus sold to Slice customers. It is true that the surplus is sold to Slice customers at the Slice rate. It is also true that the Slice rate appears to be lower than the forecast market rate that BPA assumes for the sales of the remaining surplus. But focusing on rates diverts one from the pertinent question; what are the revenues to BPA from the two sales? In the ratesetting process, it does not matter whether BPA is assuming the surplus is sold in the market or to Slice customers. In either case, BPA is realizing the same amount of revenue from the surplus. Even though BPA is selling the surplus to the Slice customers at the Slice rate, BPA is realizing the same amount of revenue within the ratesetting process.

This is illustrated by an example. Suppose BPA has surplus power valued before the section 7(b)(2) rate test at $800 million. Also, suppose that Slice customers are purchasing 25 percent of BPA's system. (We use 25 percent for simplicity, the actual amount is just over 22 percent.) In this example, we would assume that BPA would realize $600 million in surplus power sales to the market and $200 million in surplus sales to Slice customers. This is demonstrated by comparing this case to an alternative case of no Slice sales.

	No Slice	**Slice=25%**
Firm sales	7,000	5,250
Slice sales	0	1,750
Surplus sales	1,522	1,141.5
Slice surplus	0	380.5
Firm rate	27.0	27.0
Slice rate	0.0	40.1
Market rate	60.0	60.0
Firm revenue	1,656,000	1,242,000
Surplus revenue	800,000	600,000
Slice revenue	0	614,000
total revenue	2,456,000	2,456,000

In this example, Slice customers are paying a Slice rate that includes the surplus power instead of the surplus revenue credit. If, instead of receiving the surplus power, the Slice customers purchased only firm power, they would pay the lower rate, $27 per megawatt-hour in the example. By paying the $40.1 per megawatt-hour Slice rate, the Slice customers are paying an extra $200 million for the surplus power, the same amount BPA would have received if it had sold the power in the market instead of to the Slice customers.

The development of the Slice rate is such that the Slice customers are paying the weighted average of the firm rate for the firm power sales and the forecast market rate for the surplus sales. We also note that BPA receives the revenue from the Slice customers at the forecast market rate for the forecast surplus sale whether or not the surplus is generated in actual operations. Therefore, as demonstrated by this example, there is no difference in the 7(b)(2) rate test whether BPA assumes the sale of surplus power is to the market or to the Slice customers.

We address the IOUs' argument about the allocation of the 7(b)(3) reallocation amount to the Slice surplus sales in Brodie, *et al*., WP-07-E-BPA-78.

Section 16: Rate Test and COU REP Benefits

Q. The OPUC notes that in comparing the Program Case and the 7(b)(2) Case, BPA includes the cost of the REP carried out by COUs but excludes the benefit of the exchange for the COUs that receive REP payments. Hellman and McGovern, WP-07-E-PU-1 at 35. The OPUC argues that the REP costs for participating COUs should be handled by including the benefit of the REP transfer payments to the COUs as well as the cost of the REP. Id. In this manner, the Program Case will reflect that there is no net-cost imposed on COUs when COUs participate in the REP, to the extent COUs receive REP benefits. Id. The OPUC argues that by not counting the REP transfer payments to COUs, BPA is failing to take into *account the benefits some COUs receive through the REP. Id. Including the REP costs of the COUs but not the REP benefits of the COUs overstates the "harm" to the COUs. Id. Do you agree?*

A. No. The OPUC is arguing that we should reduce the Program Case rates by an amount equivalent to the REP benefits received by COUs. In essence, the OPUC is introducing a different standard into the section 7(b)(2) rate test by distinguishing between REP benefits paid to COUs and REP benefits paid to IOUs. Such a distinction would be a legal interpretation. We find no instruction in the Implementation Methodology to make such an adjustment. Also, we find no basis in the Legal Interpretation to make such a change in the Implementation Methodology. The Implementation Methodology limits the changes to the Program Case rate to the removal of Applicable 7(g) Costs. The REP benefits received by the COUs are not identified in the Legal Interpretation as an Applicable 7(g) Cost. If the Legal Interpretation is changed to support such an adjustment, we could then consider such a change to the Implementation Methodology.

Conceptually, however, it does not matter that we do not distinguish whether the recipients of REP benefits are IOUs or COUs. The predicate condition of the OPUC's argument is based on a misunderstanding of the workings of the REP. The OPUC attributes the cost of the REP as "harm" to the COUs, and by excluding the REP benefits paid the COUs in 7(b)(2) Case, the COUs are protected from the "harm" they are receiving. This argument ignores the distinction between IOUs and COUs in constructing the cost of REP. In the first case, each participating IOU receives REP benefits based on the differential between its ASC and its PF Exchange rate. Its ASC includes the costs of resources and purchases to serve its exchange load. In the second case, each participating COU also receives REP benefits based on the differential between its ASC and its PF Exchange rate. However, the COU's ASC includes its purchases from BPA at the post-section 7(b)(2) rate test PF Preference rate. In this way, the protection from the "harm" attributed to the COU is built into its ASC. Therefore, the cost of the REP removed from the 7(b)(2) Case is lower than if the COU was not purchasing at the PF Preference rate. Because of the way the COU's ASC is calculated, the OPUC's argument that we decrease the cost of the amount of REP benefits received by the COUs would amount to double-counting the COU REP benefits in the cost reductions in the 7(b)(2) Case.

Section 17: DSI Loads and Rates

Q. WPAG notes that BPA assumed for its recalculation of the 7(b)(2) rate test in the WP-02 case that it would serve 1,440 aMW of DSI load over the rate test period, which runs from FY 2002 to FY 2010. Grinberg, et al., WP-07-E-WA-05 at 29. WPAG states BPA assumed such service would be provided under the IP rate. Do you agree?

A. Yes. BPA had signed contracts that obligated it to provide 1,440 aMW of power to the DSIs from FY 2002-2006. The 7(b)(2) out-years of FY 2007-2010 are assumed to have the same DSI load obligation. *See* Hirsch, *et al.*, WP-07-E-BPA-80 for a discussion of the DSI load forecast.

Q. Cowlitz/Clark argue that BPA has updated both the section 7(c) rate allocation and its forecast of the cost of market purchases, but it failed to develop a DSI rate based on these updates. Schoenbeck and Beck, WP-07-E-JP17-01 at 30. Cowlitz/Clark argue this same approach should be reflected in the Lookback analysis as was used in the WP-02 Final Proposal. Id. Do you agree?

A. We agree that the Compromise Approach should be observed in the Lookback Analysis. We do not agree that we have failed to develop a DSI rate consistent with both the updated costs and the Compromise Approach.

Q. Cowlitz/Clark argue that maintaining this same pricing method is far more reasonable than BPA's decision to increase the amount of DSI load it was willing to serve at the section 7(c) rate even though it faced substantially greater costs for serving this load by June 2001. Schoenbeck and Beck, WP-07-E-JP17-01 at 30. If anything, the opposite decision would have been made. Id. Cowlitz/Clark argue that BPA would have decreased the amount of DSI service at the section 7(c) rate, which it in fact did. Id. Based upon BPA's forward market prices used in the Lookback studies, the pricing method BPA testified it would use to develop the final DSI rate in the WP-02 rate case produces a DSI delivered rate (including transmission) of over $43.60/MWh for the FY 2002-2006 rate period. Id. Do you agree?

A. No. Cowlitz/Clark have misapplied the Compromise Approach of calculating the WP-02 IP-TAC rate. Cowlitz/Clark assume that the 990 aMW at the section 7(c) rate and 450 aMW were fixed parameters. They were not. The 990 and 440 were results of the application of the Compromise Approach. The Compromise Approach set the target rate of $23.50/MWh for the IP-TAC rate. This rate was expected to be comprised of both cost-based Federal system power, the section 7(c)-priced amount; and purchased power, the market-priced amount. In constructing the IP-TAC rate, the melding of the $20.98/MWh 7(c)-priced power and the forecast $28.1/MWh market-priced power resulted in the $23.50/MWh IP-TAC rate.

Here we stop to note a difference between Cowlitz/Clark's simplified calculation and the more complex calculations performed in the WP-02 Final

Proposal. In the WP-02 Final Proposal there were two IP-TAC rates, one at \$23.50/MWh and one at \$25.00/MWh. Most of the 1,440 aMW of IP rate load agreed to the conditions in the Compromise Approach and 1,220 aMW was charged the \$23.50/MWh-based IP-TAC (A) rate. The remaining 230 aMW of load was charged the higher IP-TAC(B) rate.

Also, the rate calculations assumed that the DSIs purchasing under the IP-TAC rate would qualify for the Conservation & Renewable Discount, lowering the target rate to \$23.00/MWh. Taking all this into account, the calculation can be displayed as:

$$20.98 \times \alpha + 28.10 \times \beta = 23.0, \text{ and}$$

$$\alpha + \beta = 1{,}210$$

Solving the equations yield $\alpha = 870$ and $\beta = 340$. The similar calculation for the IP-TAC (B) rate would yield $\alpha = 120$ and $\beta = 110$. The sum of the two α's is 990 and the sum of the two β's is 450.

Applying the Compromise Approach in the Lookback analysis, we go through the same calculation, but replace the \$28.10/MWh five-year forecast of flat block energy purchases with the updated forecast of about \$70/MWh.

$$29.58 \times \alpha + 70.00 \times \beta = 23.50, \text{ and}$$

$$\alpha + \beta = 1{,}440$$

In this case, it is impossible to solve for α and β. If we cannot solve for the Compromise Approach rate, then it would be impossible to deliver on the agreement. However, we know that in actuality the CRACs were applied to the IP-TAC rates, and the DSIs allowed such application as meeting the Compromise Approach. Therefore, we now can assume that a rate in the range of the IP-TAC rate plus CRACs was acceptable under the Compromise Approach. The CRAC'ed IP-TAC rates were in the \$30-34/MWh range. This is where our assumed CRAC's Lookback IP rate fell. Revising the calculations assuming an average IP rate of $31 would reform our calculations to:

$$31.00 \times \alpha + 70.00 \times \beta = 31.00, \text{ and}$$

$$\alpha + \beta = 1{,}440$$

In this case, it is obvious that the solution is $\alpha = 1{,}440$ and $\beta = 0$.

Q. *Cowlitz/Clark argue that because the DSI rate was as high as $43.60/MWh, the Lookback analysis requires that an elasticity adjustment be considered with regard to the DSI smelter load. Schoenbeck and Beck, WP-07-E-JP17-01 at 30-31. Cowlitz/Clark replicated BPA's sensitivity work at a delivered power cost of $43.60/MWh and using the 5-year aluminum price forecast in the WP-02 record and found that only 365 aMW of smelter load is viable at an aluminum price of 77-80 cents per pound. Id. Cowlitz/Clark argue that a reasonable DSI smelter load reflected in the Lookback analysis should be no greater than 365 aMW. Id. Do you agree?*

A. No. Cowlitz/Clark raise the same issue as WPAG and APAC regarding the DSI load forecast, but come to a different conclusion. For the reasons stated in Hirsch, *et al.*, WP-07-E-BPA-80, the proper load forecast for the DSIs is 1,440 aMW.

Q. *APAC states that while BPA recognized price elasticity in its DSI load projections in the WP-02 case, BPA acted unreasonably when it did not recognize price elasticity in its DSI load projections in the Lookback Study. Wolverton, WP-07-E-AP-1 at 38. Instead, according to APAC, BPA increased the DSI load projected to be served by BPA firm power despite a 50 percent wholesale rate increase. Id. Do you agree that BPA recognized price elasticity in the WP-02 case but did not in the Lookback Study? Is this unreasonable?*

A. In the WP-02 rate case, price elasticity was not applied to the actual DSI load projection (1,440 aMW), but BPA did recognize price elasticity in its DSI load projection in the 7(b)(2) Case of the section 7(b)(2) rate test. Regarding the Lookback Study, we did not to apply price elasticity to any of the projected loads, including in the 7(b)(2) Case. We believe the removal of the elasticity from the 7(b)(2) Case is a reasonable assumption for purposes of the Lookback Study given the level of the 7(b)(2) Case rates. The instructions in the 1984 Implementation Methodology regarding elasticity allow us to increase DSI loads in the 7(b)(2) Case if the 7(b)(2) Case rates are significantly lower than the Program Case rates. There is no provision in the 1984 Implementation Methodology for reducing the 7(b)(2) Case DSI load forecast from the Program Case DSI load forecast. Further, the 7(b)(2) Case rates are lower than the Program Case rates, so there should be no expectation that 7(b)(2) Case DSI loads would be lower than Program Case DSI loads.

Q. *APAC notes that in 2001 BPA acknowledged that its customers may pay significantly higher prices under BPA's final WP-02 rate proposal than under BPA's May Proposal. Wolverton, WP-07-E-AP-1 at 39. Do you agree?*

A. Yes. The Lookback analysis produced FY 2002-2006 base rates that are higher than those in the WP-02 Final Proposal. The Lookback analysis has incorporated the increases in loads and costs known as of winter/spring 2001 in its base rates rather than rely on a system of CRACs.

Q. *APAC states that a DSI rate subject to the LB CRAC, FB CRAC, and SN CRAC would be in the range of $43.60/MWh, a rate that is no longer consistent with the compromise rate of about $23/MWh. Wolverton, WP-07-E-AP-1 at 40. Do you agree that the CRACs would increase the DSI rate, resulting in a rate that is inconsistent with the compromise rate?*

A. First, as stated above, the LB CRAC, FB CRAC, and SN CRACs are not applicable in the Supplemental Proposal and have no effect on the DSI rate.

Second, the \$43.60/MWh DSI rate cited by APAC is not the result of applying the various CRACs to a base IP rate. The problems with the \$43.60/MWh DSI rate cited by Cowlitz/Clark are described above. The Supplemental Proposal DSI rate is \$29.58/MWh. Given the increased costs from May 2000 to June 2001, BPA believes an increase of about \$6/MWh over the original \$23.50/MWh DSI rate can still be considered consistent with the Compromise Approach. The much higher Cowlitz/Clark DSI rate, which is about \$20/MWh higher than the original \$23.50/MWh DSI rate, may not be consistent.

Q. APAC states that in the Supplemental Proposal BPA assumes that the DSls would be offered a \$23.50/MWh rate when all other customers were paying over \$30/MWh. Wolverton, WP-07-E-AP-1 at 40. APAC further states that BPA "would have us believe that it could have fashioned such a rate" but does not provide any evidence that it could have made such an offer. Id. Do you agree?

A. APAC appears confused. In the Supplemental Proposal the IP rate is \$29.58/MWh and BPA forecasts sales of 1,440 aMW at that average price. Nowhere in the Supplemental Proposal are the DSIs offered power at \$23.50/MWh as APAC contends.

Q. Does this conclude your testimony?

A. Yes.

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Attachment 1 - Revenue Requirements

Program and 7(b)(2) Cases
Comparisons of Interest, Amortization and Net Revenues
($thousands)

Total Revenue Requirement:							
Net Interest Expense	**2009**	**2010**	**2011**	**2012**	**2013**	**Total**	**cited**
Program Case	155,981	162,545	171,415	175,676	186,441		
7(b)(2) Case	136,107	143,120	150,111	155,432	166,816		
variance 7b2 - Program	(19,874)	(19,425)	(21,304)	(20,244)	(19,625)	(100,472)	381,186
Planned Net Revenues							
Program Case	0	56,356	33,317	0	44,458		
7(b)(2) Case	20,039	112,735	94,532	13,247	70,200		
variance 7b2 - Program	20,039	56,378	61,214	13,247	25,742	176,621	218,482
FBS Net Interest:							
Program Case	137,283	142,165	148,691	156,572	167,392		
7(b)(2) Case	135,368	142,324	149,214	154,454	165,736		
variance 7b2 - Program	(1,915)	159	523	(2,118)	(1,656)	(5,007)	381,186
FBS Planned Net Revenues							
Program Case	0	49,290	28,900	0	39,555		
7(b)(2) Case	19,930	112,108	93,967	13,163	69,745		
variance 7b2 - Program	19,930	62,818	65,067	13,163	30,190	191,168	218,482
Gross Interest (rep study)							
Program Case	264,953	273,657	283,995	290,916	303,014		
7(b)(2) Case	243,416	250,428	257,420	262,741	274,126		
variance 7b2 - Program	(21,538)	(23,229)	(26,575)	(28,175)	(28,888)	(128,404)	
Amortization (rep study)							
Program Case	103,065	201,205	184,130	99,211	112,800		
7(b)(2) Case	102,079	202,981	186,935	107,947	110,654		
variance 7b2 - Program	(986)	1,776	2,805	8,736	(2,146)	10,185	
Conservation Amortization	51,446	56,652	62,802	53,748	55,008	279,657	

Hydro Expense Increase
(Dollars in 1,000s)

RAM	Net Interest	Planned	Total Cost
2002-2006	382,650	192,925	575,575
2007-2008	1,186	336,941	338,127
2009	(2,650)	218,482	215,832
Total:	381,186	748,348	1,129,534

Short-Term Bridge

Draft Prototype

NEW RESOURCE FIRM POWER BLOCK

POWER SALES AGREEMENT

executed by the

BONNEVILLE POWER ADMINISTRATION

and

«FULL NAME OF CUSTOMER»

Table of Contents

This BLOCK POWER SALES AGREEMENT (Agreement) is executed by the UNITED STATES OF AMERICA, Department of Energy, acting by and through the BONNEVILLE POWER ADMINISTRATION (BPA), and «FULL NAME OF CUSTOMER» («Customer Name»). «Customer Name» is an investor-owned utility organized under the laws of the State of «____________».

RECITALS

BPA has administratively divided its organization into two business lines in order to functionally separate the administration and decision-making activities of BPA's power business from the administrative and decision-making activities of its transmission business. References in this Agreement to the Power Business Line (PBL) are solely for the purpose of establishing which BPA business line is responsible for the administration of this Agreement.

BPA and «Customer Name» agree:

1. TERM*(05/05/00 Version)*

This Agreement takes effect on the date signed by BPA and «Customer Name» (Effective Date), and shall continue in effect until 2400 hours on September 30, 2011.

2. TERMINATION OF PRIOR AGREEMENT

Effective on the Effective Date, Contract No. 00PB-XXXXX between BPA and «Customer Name» is terminated.

3. DEFINITIONS*(04/27/00 Version)*

Capitalized terms in this Agreement shall have the meanings defined below, in the exhibits or in context. All other capitalized terms and acronyms are defined in BPA's applicable Wholesale Power Rate Schedules, including the General Rate Schedule Provisions (GRSPs), or its successors.

(a) "Alternate Supplier"***(04/27/00 Version)*** means an entity, other than «Customer Name», or a consumer of «Customer Name» serving its own load with an on site resource, that provides electric power service directly to a retail electric power consumer that receives service over the distribution system of «Customer Name» under Voluntary Retail Access or Mandated Retail Access.

(b) "Amounts Taken"***(04/27/00 Version)*** means an amount deemed equal to the amount of power scheduled by «Customer Name» under section 8 of this Agreement or an amount of power as measured at Points of Measurement, as appropriate.

(c) "Annexed Load"***(09/05/00 Version)*** means the amount of load, including the increase in load associated with an annexation, that is added to «Customer Name»'s distribution system after September 30, 2000, due to «Customer Name» acquisition by condemnation, purchase or other legal process, as authorized under applicable state law, of distribution facilities and the obligation to serve the retail electric power consumers connected to the facilities. Annexed Load amounts are shown in Exhibit A, Rate Commitments.

(d) "Contract Year" or "CY"***(04/27/00 Version)*** means the period that begins each October 1 and which ends the following September 30. For instance, Contract Year 2008 begins October 1, 2007, and continues through September 30, 2008.

(e) "Diurnal"***(04/27/00 Version)*** means the division of hours of the day between Heavy Load Hours (HLH) and Light Load Hours (LLH).

(f) "Firm Power"***(04/27/00 Version)*** means electric power that PBL will make continuously available to «Customer Name» under this Agreement.

(g) "Mandated Retail Access"***(06/02/00 Version)*** means the right, mandated either by Federal, or state law of retail electric power consumers to either acquire electric power service directly from one or more Alternate Suppliers of such electric power, or choose electric power service from a portfolio of power supply options, without «Customer Name» taking an ownership interest.

(h) "New Large Single Load" or "NLSL"***(04/27/00 Version)*** means the definition established for NLSL in the Northwest Power Act, as implemented in a NLSL policy developed by BPA after this Agreement is executed.

(i) "Northwest Power Act"***(04/27/00 Version)*** means the Pacific Northwest Electric Power Planning and Conservation Act of 1980, P.L. 96-501.

(j) "Party" or "Parties"***(04/27/00 Version)*** means PBL and/or «Customer Name».

(k) "Points of Measurement"***(04/27/00 Version)*** means the interconnection points between BPA, «Customer Name» and other control areas, as applicable. Electric power amounts are established at these points based on metered amounts or scheduled amounts, as appropriate.

(l) "Points of Receipt"***(04/27/00 Version)*** means the points of interconnection on the transmission provider's transmission system where Firm Power will be made available to «Customer Name»'s transmission provider by PBL.

(m) "Power Business Line" or "PBL"***(09/05/00 Version)*** means the administrative unit of the Bonneville Power Administration, United States Department of Energy, or its successor, which is acting by and for BPA in making this contract, and which is responsible for the management of marketing and sale of Federal power under BPA statutes.

(n) "Region"***(04/27/00 Version)*** means the definition established for "Region" in the Northwest Power Act.

(o) "Returned Retail Load"***(04/27/00 Version)*** means a retail electric power consumer load that returns to «Customer Name» for electric power service after receiving electric power service from an Alternate Supplier.

(p) "Surplus Firm Power"***(04/27/00 Version)*** means surplus firm electric power that is made available and sold consistent with section 5(f) of the Northwest Power Act and subject to the provisions of P.L. 88-552 which is made available under this Agreement.

(q) "Total Retail Load"***(04/27/00 Version)*** means all electric power consumption including electric system losses, within a utility's distribution system as measured at Points of Measurement, adjusted as needed for unmetered loads or generation, nonfirm or interruptible loads agreed to by the Parties, transfer loads of other utilities served by «Customer Name» and «Customer Name»'s transfer loads located in other control areas, and losses on «Customer Name»'s transmission system. No distinction is made between load that is served with Firm Power and load that is served with electric power from other sources.

(r) "Transmission Business Line" or "TBL"***(04/27/00 Version)*** means that portion of the BPA organization or its successor that is responsible for the management and sale of transmission service on the Federal Columbia River Transmission System (FCRTS).

(s) "Voluntary Retail Access"***(06/02/00 Version)*** means retail access that is not Mandated Retail Access and under which the retail electric power consumer has the ability to either acquire electric power service directly from one or more Alternate Suppliers of such electric power, or choose electric power service from a portfolio of power supply options, without «Customer Name» taking an ownership interest.

4. APPLICABLE RATES*(06/27/00 Version)*
The New Resource Firm Power (NR) rate schedule, including the GRSPs, or their successors, apply to Firm Power purchases under this Agreement.

5. NEW RESOURCE FIRM POWER BLOCK PRODUCT*(04/27/00 Version)*

(a) **Purchase and Sale of Block Product*(04/27/00 Version)***
PBL shall sell and make available and «Customer Name» shall purchase under the applicable NR rates each hour the Firm Power amounts as established in section 5(b) below.

(b) **Establishment of Block Power Amounts**
«Customer Name» may, upon written notice to BPA, request Firm Power service from BPA. Any such notice shall specify, for each month of the term of the purchase, an equal amount of Firm Power in all hours of each such month. Upon mutual agreement by BPA and «Customer Name» of the terms and conditions for such Firm Power service, the Parties shall amend this Agreement to reflect such amounts in the table below.

Contract Year	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sept

Contract Year	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sept
Total MW												
HLH MW												
LLH MW												

6. **LOAD LOSS**

(a) **Limitation on Damages*(09/05/00 Version)***
Up to 60 days after the end of each Contract Year, PBL may determine if «Customer Name» purchased less Firm Power, due to load loss established in section 5 of Exhibit C, Net Requirements, in any month during the previous Contract Year than it was contractually obligated to purchase under this Agreement (Monthly Purchase Deficiency). If PBL makes such a determination it shall calculate the reasonable market value of each Monthly Purchase Deficiency taking into account the differing market values within each month during such Contract Year. «Customer Name» shall pay PBL damages for such Contract Year equal to the amount by which the sum of the product of the Monthly Purchase Deficiencies and the amount PBL would have charged if the power had been taken under this Agreement, exceeds the sum of the product of the Monthly Purchase Deficiencies and the reasonable market value in each month. PBL may require through a written notice to «Customer Name» that «Customer Name» provide a reasonable forecast of its expected load loss amounts for a Contract Year.

(b) **Returned Retail Loads*(04/27/00 Version)***
«Customer Name» shall notify PBL of any Returned Retail Load and provide PBL with metering information for such loads prior to PBL providing any power to serve such loads. «Customer Name» agrees not to request from PBL service under section 5(b) of the Northwest Power Act for a Returned Retail Load which would commence earlier than one year after the date the Returned Retail Load began receiving service from the Alternate Supplier. Any request for service to Returned Retail Loads would be established pursuant to section 4(c) of Exhibit A, Rate Commitments.

7. **RETAIL ACCESS IMPLEMENTATION*(04/27/00 Version)***
At least 180 days before «Customer Name» allows Voluntary Retail Access or before the effective date of Mandated Retail Access, the Parties shall amend the terms of this Agreement, if and to the extent necessary, to reflect the following «Customer Name» obligations:

(a) «Customer Name» shall ensure that PBL has access to information adequate to plan, schedule, and bill for service rendered under this Agreement; and

(b) «Customer Name» shall ensure that any retail electric power consumer, that receives all or a portion of its power supply from an Alternate Supplier, acquires all services necessary to support such service, including without limitation energy imbalance service.

8. SCHEDULING*(04/27/00 Version)*

All Firm Power transactions under this Agreement shall be scheduled and implemented consistent with Exhibit E, Scheduling. The procedures for scheduling described in Exhibit E, Scheduling are the standard utility procedures followed by PBL for power transactions between PBL and other utilities or entities in the Region that require scheduling.

9. DELIVERY

(a) **Transmission Service for Firm Power*(04/27/00 Version)***

This Agreement does not provide transmission services for, or include the delivery of, Firm Power to «Customer Name». «Customer Name» shall be responsible for executing one or more wheeling agreements with a transmission supplier for the delivery of Firm Power (Wheeling Agreement). The Parties agree to take such actions as may be necessary to facilitate the delivery of Firm Power to «Customer Name» consistent with the terms, notice, and the time limits contained in the Wheeling Agreement.

(b) **Liability for Delivery(04/27/00 Version)**

«Customer Name» waives any claims against PBL arising under this Agreement for nondelivery of power to any points beyond the applicable Points of Receipt. PBL shall not be liable for any third-party claims related to the delivery of power after it leaves the Points of Receipt. In no event will either Party be liable under this Agreement to the other Party for damage that results from any sudden, unexpected, changed, or abnormal electrical condition occurring in or on any electric system, regardless of ownership. These limitations on liability apply regardless of whether or not this Agreement provides for transfer service.

(c) **Points of Receipt*(06/27/00 Version)***

PBL shall make Firm Power available to «Customer Name» under this Agreement at Points of Receipt solely for the purpose of scheduling transmission to points of delivery on «Customer Name»'s distribution system. «Customer Name» shall schedule, if scheduling is necessary, such Firm Power solely for use by its firm retail electric power consumer load. PBL, for purposes of scheduling transmission for delivery under this Agreement, shall specify Points of Receipt in a written notice to «Customer Name» 18 months after «Customer Name» provides notice that it desires to purchase power from BPA, as required by section 5(b) of this Agreement.

If required by the Wheeling Agreement when PBL designates such Points of Receipt, PBL will provide capacity amounts for transmission under the Wheeling Agreement associated with the initial Points of Receipt that can be accepted as firm Points of Receipt under «Customer Name»'s Wheeling Agreement (except in the event that all Points of Receipt on the Federal Columbia River Power System (FCRPS) would be considered nonfirm). The sum of capacity amounts requested by PBL shall not exceed the amount reasonably necessary for PBL to provide Firm Power. Such Points of Receipt and their capacity amounts may only be changed through mutual agreement. However, at any time PBL may request the use of nonfirm Points of Receipt to provide Firm Power to «Customer Name», but notwithstanding section 9(b) above, PBL shall reimburse «Customer Name» for any additional costs incurred by «Customer Name» due to its compliance with such request.

(d) **Transmission Losses(04/27/00 Version)**
PBL shall provide «Customer Name» the losses, between the Points of Receipt and the point of interconnection between the BPA Control Area and the Control Area in which «Customer Name» resides, for Firm Power, at no additional charge. Losses will be provided at Points of Receipt as established under section 9(c), and under the terms and conditions as defined in the transmission provider's tariff.

10. MEASUREMENT*(04/27/00 Version)*
Amounts Taken are deemed equal to the amount scheduled by «Customer Name» under section 8 of this Agreement or an amount of power as measured at Points of Measurement, as appropriate.

11. BILLING AND PAYMENT

(a) **Billing*(06/09/00 Version)***
PBL shall bill «Customer Name» monthly, consistent with applicable BPA rates, including the GRSPs and the provisions of this Agreement for the Firm Power, Unauthorized Increase Charges, payments pursuant to section 5, and other services provided to «Customer Name» in the preceding month or months under this Agreement. PBL may send «Customer Name» an estimated bill followed by a final bill. PBL shall send all bills on the bill's issue date either electronically or by mail, at «Customer Name»'s option. If electronic transmittal of the entire bill is not practical, PBL shall transmit a summary electronically, and send the entire bill by mail.

(b) **Payment*(04/27/00 Version)***
Payment of all bills, whether estimated or final, must be received by the 20th day after the issue date of the bill (Due Date). If the 20th day is a Saturday, Sunday, or Federal holiday, the Due Date is the next business day. If payment has been made on an estimated bill before receipt of a final bill for the same month, «Customer Name» shall pay only the amount by which the final bill exceeds the payment made for the estimated bill. PBL shall provide «Customer Name» the amounts by which an estimated bill exceeds a final bill through either a check or as a credit on the subsequent month's bill. After the Due Date, a late payment charge shall be applied each day to any unpaid balance. The late payment charge is calculated by dividing the Prime Rate for Large Banks as reported in the Wall Street Journal, plus 4 percent by 365. The applicable Prime Rate for Large Banks shall be the rate reported on the first day of the month in which payment is received. «Customer Name» shall pay by electronic funds transfer using BPA's established procedures.

PBL may terminate this Agreement if «Customer Name» is more than three months behind in paying its bills under this Agreement and «Customer Name» cannot demonstrate an ability to make the payments owed.

(c) **Disputed Bills*(04/27/00 Version)***
In case of a billing dispute, «Customer Name» shall note the disputed amount and pay its bill in full by the Due Date. Unpaid bills (including both disputed and undisputed amounts) are subject to late payment charges provided above. If «Customer Name» is entitled to a refund of any portion of the disputed amount, then BPA shall make such refund with simple interest computed from the date of receipt of the disputed payment to the date the refund is made. The daily interest rate used to determine the interest is calculated by dividing the Prime Rate for Large Banks as reported in the Wall Street Journal; by 365. The applicable Prime Rate for Large Banks shall be the rate reported on the first day of the month in which payment is received by BPA.

12. NOTICES*(04/27/00 Version)*
Any notice required under this Agreement shall be in writing and shall be delivered: (a) in person; (b) by a nationally recognized delivery service; or (c) by United States Certified Mail. Notices are effective when received. Either Party may change its address for notices by giving notice of such change consistent with this section.

If to «Customer Name»:

«Customer Name»
«Street»
«City, State, Zip»
Attn: «Contact»
«Title»
Phone: «Phone»
FAX: «FAX»
E-Mail: «e-mail address»

If to PBL:

Bonneville Power Administration
P.O. Box 3621
Portland, OR 97208-3621
Attn: «AE»
Phone: 206-220-«____»
FAX: 206-220-«____»
E-Mail: «AE e-mail address»

13. COST RECOVERY*(04/27/00 Version)*

(a) Nothing included in or omitted from this Agreement creates or extinguishes any right or obligation, if any, of BPA to assess against «Customer Name» and «Customer Name» to pay to BPA at any time a cost underrecovery charge pursuant to an applicable transmission rate schedule or otherwise applicable law.

(b) BPA may adjust the rates for Firm Power set forth in the applicable power rate schedule during the term of this Agreement pursuant to the Cost Recovery Adjustment Clause in the 2002 GRSPs, or successor GRSPs.

14. UNCONTROLLABLE FORCES*(04/27/00 Version)*

PBL shall not be in breach of its obligation to provide Firm Power and «Customer Name» shall not be in breach of its obligation to purchase Firm Power to the extent the failure to fulfill that obligation is due to an Uncontrollable Force. "Uncontrollable Force" means an event beyond the reasonable control of, and without the fault or negligence of, the Party claiming the Uncontrollable Force that impairs that Party's ability to perform its contractual obligations under this Agreement and which, by exercise of that Party's reasonable diligence and foresight, such Party could not be expected to avoid and was unable to avoid. Uncontrollable Forces include, but are not limited to:

(a) any unplanned curtailment or interruption for any reason of firm transmission used to deliver Firm Power to «Customer Name»'s facilities or distribution system, including but not limited to unplanned maintenance outages;

(b) any unplanned curtailment or interruption, failure or imminent failure of «Customer Name»'s distribution facilities, including but not limited to unplanned maintenance outages;

(c) any planned transmission or distribution outage that affects either «Customer Name» or PBL which was provided by a third-party transmission or distribution owner, or by a transmission provider, including TBL, that is functionally separated from the generation provider in conformance with Federal Energy Regulatory Commission (FERC) Orders 888 and 889 or its successors;

(d) strikes or work stoppage, including the threat of imminent strikes or work stoppage;

(e) floods, earthquakes, or other natural disasters; and

(f) orders or injunctions issued by any court having competent subject matter jurisdiction, or any order of an administrative officer which the Party claiming the Uncontrollable Force, after diligent efforts, was unable to have stayed, suspended, or set aside pending review by a court of competent subject matter jurisdiction.

Neither the unavailability of funds or financing, nor conditions of national or local economies or markets shall be considered an Uncontrollable Force. The economic hardship of either Party shall not constitute an Uncontrollable Force. Nothing contained in this provision shall be construed to require either Party to settle any strike or labor dispute in which it may be involved.

The Party claiming the Uncontrollable Force shall notify the other Party as soon as practicable of that Party's inability to meet its obligations under this Agreement due to an Uncontrollable Force. The Party claiming the Uncontrollable Force also agrees to notify any control area involved in the scheduling of a transaction which may be curtailed due to an Uncontrollable Force.

Both Parties shall be excused from their respective obligations, other than from payment obligations incurred prior to the Uncontrollable Force, without liability to the other, for the duration of the Uncontrollable Force and the period reasonably required for the Party claiming the Uncontrollable Force, using due diligence, to restore its operations to conditions existing prior to the occurrence of the Uncontrollable Force.

15. GOVERNING LAW AND DISPUTE RESOLUTION*(09/05/00 Version)*

(a) This Agreement shall be interpreted consistent with and governed by Federal law. Final actions subject to section 9(e) of the Northwest Power Act are not subject to binding arbitration and shall remain within the exclusive jurisdiction of the United States Ninth Circuit Court of Appeals. Any dispute regarding any rights of the Parties under any BPA policy, including the implementation of such policy, shall not be subject to arbitration under this Agreement. «Customer Name» reserves the right to seek judicial resolution of any dispute arising under this Agreement that is not subject to arbitration under this section 15. For purposes of this section 15 BPA policy means any written document adopted by BPA as a final action in a decision record or record of decision that establishes a policy of general application, or makes a determination under an applicable statute. If either Party asserts that a dispute is excluded from arbitration under this section 15, either Party may apply to the Federal court having jurisdiction for an order determining whether such dispute is subject to arbitration under this section 15.

(b) Any contract dispute or contract issue between the Parties arising out of this Agreement, except for disputes that are excluded through section 15(a) above, shall be subject to binding arbitration. The Parties shall make a good faith effort to resolve such disputes before initiating arbitration proceedings. During arbitration, the Parties shall continue performance under this Agreement pending resolution of the dispute, unless to do so would be impossible or impracticable.

(c) Any arbitration shall take place in Portland, Oregon, unless the Parties agree otherwise. The CPR Institute for Dispute Resolution's arbitration procedures for commercial arbitration, Non-Administered Arbitration Rules (CPR Rules), shall be used for each dispute; *provided, however*, that: (1) the Parties shall have the discovery rights provided in the Federal Rules of Civil Procedure unless the Parties agree otherwise; and (2) for claims of $1 million or more, each arbitration shall be conducted by a panel of three neutral arbitrators. The Parties shall select the arbitrators from a list containing the names of 15 qualified individuals supplied by the CPR Institute for Dispute Resolution. If the Parties cannot agree upon three arbitrators on the list within 20 business days, the Parties shall take turns striking names from the list of proposed arbitrators. The Party initiating the arbitration shall take the first strike. This process shall be repeated until three arbitrators remain on the list, and those individuals shall be designated as the arbitrators. For disputes involving less than $1 million, a single neutral arbitrator shall be selected consistent with section 6 of the CPR Rules.

(d) Except for arbitration awards which declare the rights and duties of the Parties under this Agreement, the payment of monies shall be the exclusive remedy available in any arbitration proceeding. Under no circumstances shall specific performance be an available remedy against BPA. The arbitration award shall be final and binding on both Parties, except that either Party may seek judicial review based upon any of the grounds referred to in the Federal Arbitration Act, 9 U.S.C. §1-16 (1988). Judgment upon the award rendered by the arbitrators may be entered by any court having jurisdiction thereof.

(e) Each Party shall be responsible for its own costs of arbitration, including legal fees. The arbitrators may apportion all other costs of arbitration between the Parties in such manner as they deem reasonable taking into account the circumstances of the case, the conduct of the Parties during the proceeding, and the result of the arbitration.

16. STATUTORY PROVISIONS

(a) **Annual Financial Report and Retail Rate Schedules*(04/27/00 Version)***
«Customer Name» shall provide PBL with a current copy of its annual financial report and its retail rate schedules, as required by Section 5(a) of the Bonneville Project Act, P.L. 75-329.

(b) **Insufficiency and Allocations*(04/27/00 Version)***
If BPA determines, consistent with section 5(b) of the Northwest Power Act and other applicable statutes, that it will not have sufficient resources on a planning basis to serve its loads after taking all actions required by applicable laws then BPA shall give «Customer Name» a written notice that BPA may restrict service. Such notice shall be consistent with BPA's insufficiency and allocations methodology, published in the Federal Register on March 20, 1996, and shall state the effective date of the restriction, the amount of «Customer Name»'s load to be restricted, and the expected duration of the restriction. BPA shall not change that methodology without the written agreement of all affected customers. Such restriction shall take effect no sooner than five years after notice is given to «Customer Name». If BPA imposes a restriction under this provision then the amount of Firm Power that «Customer Name» is obligated to purchase pursuant to section 5 shall be reduced to the amounts available under such restricted service.

(c) **New Large Single Loads*(09/05/00 Version for Block)***

(1) **General**
All existing NLSLs are listed in section 5 of Exhibit A, Rate

Commitments. «Customer Name» shall provide reasonable notice to PBL of any expected increase in load that is likely to qualify as a new NLSL. «Customer Name» may either serve a NLSL with Firm Power or with power from another source. For purposes of this section 16(c), "Consumer" means an end-user of electric power or energy.

(2) **Determination of a Facility**
PBL, in consultation with «Customer Name», shall make a reasonable determination of what constitutes a single facility, for the purpose of identifying a NLSL, based upon the following criteria:

(A) whether the load is operated by a single Consumer;

(B) whether the load is in a single location;

(C) whether the load serves a manufacturing process which produces a single product or type of product;

(D) whether separable portions of the load are interdependent;

(E) whether the load is contracted for, served or billed as a single load under «Customer Name»'s customary billing and service policy;

(F) consistent application of the foregoing criteria in similar fact situations; and

(G) any other factors the Parties determine to be relevant.

PBL shall show an increase in load associated with a Consumer's facility which has been determined to be a NLSL in section 5 of Exhibit A, Rate Commitments. PBL shall have the unilateral right to amend Exhibit A to reflect such determinations when made.

(3) **Determination of Ten Average Megawatt Increase**
An increase in load shall be considered a NLSL if the energy consumption of the Consumer's load associated with a new facility, an existing facility, or expansion of an existing facility during the immediately past 12-month period exceeds by 10 average megawatts or more the Consumer's energy consumption for such new facility, existing facility or expansion of an existing facility for the consecutive 12-month period one year earlier, or the amount of the contracted for, or committed to load of the Consumer as of September 1, 1979, whichever is greater.

(4) **CF/CT Loads**
The following loads were determined by the Administrator to be

contracted for, or committed to, as of September 1, 1979, as defined in section 3(13)(A) of the Northwest Power Act, and are subject to the applicable rate for the rest (non-NLSL) of «Customer Name»'s load:

[OPTIONS for section 16(c)(4).
Option 1-Include the following if customer has no CF/CT loads.

(4) **CF/CT Loads**
«Customer Name» has no loads that were contracted for, or committed to, as of September 1, 1979, as defined in section 3(13)(A) of the Northwest Power Act.

Option 2-Include the following if customer has CF/CT loads.

(4) **CF/CT Loads**
The following loads were determined by the Administrator to be contracted for, or committed to, as of September 1, 1979, as defined in section 3(13)(A) of the Northwest Power Act, and are subject to the applicable rate for the rest (non-NLSL) of «Customer Name»'s load:

Retail electric power consumer's name:

Amount of firm energy contracted for, or committed to, as of September 1, 1979:

Facility description:

End of OPTIONS for section 16(c)(4).]

(d) **Priority of Pacific Northwest Customers*****(04/27/00 Version)***
The provisions of sections 9(c) and (d) of the Northwest Power Act and the provisions of P.L. 88-552 as amended by the Northwest Power Act are incorporated into this Agreement by reference. BPA agrees that «Customer Name», together with other customers in the Region shall have priority to BPA power, consistent with such provisions.

(e) **Prohibition on Resale*****(04/27/00 Version)***
«Customer Name» shall not resell NR Firm Power except to serve «Customer Name»'s Total Retail Load or as otherwise permitted by Federal law.

(f) **Use of Regional Resources*****(04/27/00 Version)***

(1) Within 60 days prior to the start of each Contract Year, «Customer Name» shall notify PBL of any firm power from a generating resource, or a contract resource during its term, that has been used to serve firm consumer load in the Region that «Customer Name» plans to export for sale outside the Region in the next Contract Year. PBL may during such Contract Year request additional information on «Customer Name» resources if PBL has information that «Customer Name» may have made such an export and not notified PBL. PBL may request and «Customer Name» shall provide within 30 days of

such request, information on the planned use of any or all of «Customer Name»'s generating and contractual resources.

(2) «Customer Name» shall be responsible for monitoring any firm power from generating resources and contract resources it sells in the Region to ensure such firm power is delivered to be used to serve firm consumer load in the Region.

(3) If «Customer Name» fails to report to PBL in accordance with section (1), above, any of its planned exports for sale outside the Region of firm power from a generating resource or a contract resource that has been used to serve firm consumer load in the Region, and PBL makes a finding that an export which was not reported was made, then PBL may terminate this Agreement upon 30 days written notice to «Customer Name». If PBL concludes that the failure to report is inadvertent and unlikely to reoccur PBL shall not terminate this Agreement and may instead elect to decrement the amount of Firm Power by up to two times the amount of the export that was not reported. When applicable such decrements shall be established consistent with section 4(c) of Exhibit C.

(4) For purposes of this section, an export for sale outside the Region means a contract for the sale or disposition of firm power from a generating resource, or a contract resource during its term, that has been used to serve firm consumer load in the Region in a manner that such output is not planned to be used solely to serve firm consumer load in the Region. Delivery of firm power outside the Region under a seasonal exchange agreement that is made consistent with BPA's section 9(c) policy will not be considered an export. Firm power from a generating resource or contract resource used to serve firm consumer load in the Region means the firm generating or load carrying capability of a generating resource or contract resource as established under Pacific Northwest Coordination Agreement resource planning criteria, or other resource planning criteria generally used for such purposes within the Region.

(g) **BPA Appropriations Refinancing Act*(04/27/00 Version)***
The Parties agree that the BPA Refinancing Section of the Omnibus Consolidated Recisions and Appropriations Act of 1996 (The BPA Refinancing Act), P.L. No. 104-134, 110 Stat. 1321, 1350, as stated in the United States Code on the date this Agreement is signed by the Parties, is incorporated by reference and is a material term of this Agreement. The Parties agree that this provision and the incorporated text shall be included in subsequent agreements between the Parties, as a material term through at least September 30, 2011.

17. STANDARD PROVISIONS

(a) **Amendments*(04/27/00 Version)***
No oral or written amendment, rescission, waiver, modification, or other change of this Agreement shall be of any force or effect unless set forth in a written instrument signed by authorized representatives of each Party.

(b) **Assignment*(04/27/00 Version)***
This Agreement is binding on any successors and assigns of the Parties. BPA may assign this Agreement to another Federal agency to which BPA's statutory duties have been transferred. Neither Party may otherwise transfer or assign this Agreement, in whole or in part, without the other Party's written consent. Such consent shall not be unreasonably withheld. BPA shall consider any request for assignment consistent with applicable BPA statutes. «Customer Name» may not transfer or assign this Agreement to any of its retail customers.

(c) **Information Exchange and Confidentiality*(09/05/00 Version for Block)***
The Parties shall provide each other with any information that is reasonably required, and requested by either Party in writing, to operate under and administer this Agreement, including load forecasts for planning purposes, information needed to resolve billing disputes, scheduling and metering information reasonably necessary to prepare power bills that is not otherwise available to the requesting Party, including metering data for each load that qualifies as an NLSL. Such information shall be provided in a timely manner. Information may be exchanged by any means agreed to by the Parties. If such information is subject to a privilege of confidentiality, a confidentiality agreement or statutory restriction under state or Federal law on its disclosure by a Party to this Agreement, then that Party shall endeavor to obtain whatever consents, releases, or agreements are necessary from the person holding the privilege to provide such information while asserting the confidentiality over the information. Information provided to BPA which is subject to a privilege of confidentiality or nondisclosure shall be clearly marked as such and BPA shall not disclose such information without obtaining the consent of the person or Party asserting the privilege, consistent with BPA's obligation under the Freedom of Information Act. BPA may use such information as necessary to provide service or timely bill for service under this Agreement. BPA shall only disclose information received under this provision to BPA employees who need the information for purposes of this Agreement.

(d) **Entire Agreement*(04/27/00 Version)***
This Agreement, including all provisions, exhibits incorporated as part of this Agreement, and documents incorporated by reference, constitutes the entire agreement between the Parties. It supersedes all previous communications, representations, or contracts, either written or oral, which purport to describe or embody the subject matter of this Agreement.

(e) **Exhibits*(04/27/00 Version)***
The exhibits listed in the table of contents are incorporated into this Agreement by reference. The exhibits may only be revised upon mutual agreement between the Parties unless otherwise specified in the exhibits. The body of this Agreement shall prevail over the exhibits to this Agreement in the event of a conflict.

(f) **No Third-Party Beneficiaries*(04/27/00 Version)***
This Agreement is made and entered into for the sole protection and legal benefit of the Parties, and no other person shall be a direct or indirect legal beneficiary of, or have any direct or indirect cause of action or claim in connection with this Agreement.

(g) **Waivers*(04/27/00 Version)***
Any waiver at any time by either Party to this Agreement of its rights with respect to any default or any other matter arising in connection with this Agreement shall not be considered a waiver with respect to any subsequent default or matter.

(h) **BPA Policies*(04/27/00 Version)***
Any reference in this Agreement to BPA policies, including without limitation BPA's NLSL Policy and the 5(b)/9(c) Policy, and any revisions thereto, does not constitute agreement by «Customer Name» to such policy, nor shall it be construed to be a waiver of the right of «Customer Name» to seek judicial review of any such policy.

(i) **Severability*(04/27/00 Version)***
If any term of this Agreement is found to be invalid by a court of competent jurisdiction then such term shall remain in force to the maximum extent permitted by law. All other terms shall remain in force unless that term is determined not to be severable from all other provisions of this Agreement by such court.

(j) **Rate Covenant*(04/27/00 Version)***
«Customer Name» agrees that it will establish, maintain, and collect rates or charges for power and energy and other services, facilities and commodities sold, furnished or supplied by it through any of its electric utility properties which, in the judgment of «Customer Name», shall be adequate to provide revenues sufficient to enable «Customer Name» to make the payments required under this Agreement.

18. SIGNATURES*(04/27/00 Version)*
The signatories represent that they are authorized to enter into this Agreement on behalf of the party for whom they sign.

«FULL NAME OF CUSTOMER»	UNITED STATES OF AMERICA Department of Energy Bonneville Power Administration
By ____________________	By ____________________ Account Executive
Name ____________________ *(Print/Type)*	Name ____________________ *(Print/Type)*
Date ____________________	Date ____________________

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Exhibit A
RATE COMMITMENTS

1. PURCHASE DURATION*(04/27/00 Version)*
«Customer Name» shall purchase all of the Firm Power as established in section 5 of the body of this Agreement for the term specified in such section 5.

2. SPECIAL NR LOAD TREATMENT

(a) **Annexed Loads*(04/27/00 Version)***
«Customer Name» agrees to serve any Annexed Loads with resource amounts added consistent with section 4 of Exhibit C, Net Requirement except as follows: Annexed Load amounts that were served by PBL under section 5(b) of the Northwest Power Act immediately prior to becoming an Annexed Load will be provided service under rates, terms, and conditions that, within the constraints of BPA's applicable policies, are as comparable as possible to what such Annexed Load would have received if the load had not become an Annexed Load. When «Customer Name» has an Annexed Load this exhibit shall be revised to include estimated monthly HLH and LLH MWs in a table below.

(b) **Returned Retail Load*(06/09/00 Version)***
«Customer Name» may request service from PBL to serve Returned Retail Load in time periods where the amount of Firm Power as established in section 5 of the body of this Agreement has been reduced due to load loss. The Returned Retail Load Amount served by PBL under this Agreement may not exceed the difference between the original amount and the amount established in section 5 of Exhibit C. The Parties shall revise this exhibit to establish monthly HLH and LLH MWs for such service in a table below. The table shall identify whether the amounts in the table are deemed to be actual for billing purposes or whether the table is an estimate with bills based on metered amounts. PBL shall provide service within 180 days of the request at rates BPA has established or establishes as applicable to such loads. The rate treatment for such loads shall continue through Contract Year 2006. Rate treatment after Contract Year 2006 shall be determined in a future rate case.

(d) **Load Previously Served By «Customer Name» Northwest Power Act Sections 5(b)(1)(A) and/or 5(b)(1)(B) Resources*(04/27/00 Version)***
«Customer Name» may request service from PBL to serve load that would otherwise be served by «Customer Name»'s Northwest Power Act sections 5(b)(1)(A) resources and 5(b)(1)(B) generating resources and long-term contract resources that are removed consistent with section 4(d) of Exhibit C, Net Requirements. The Parties shall revise this exhibit to establish monthly HLH and LLH MWs for such service in a table below. The amounts are deemed to be actual for billing purposes. PBL shall provide service within 180 days of the request at rates BPA has established or establishes as applicable to such loads. Rate treatment for such loads shall be determined in each rate case.

3. NEW LARGE SINGLE LOADS*(04/27/00 Version)*

(Drafter's Note: For each NLSL in this section include the following: the retail electric power consumer name, the facility location, the date the load became a NLSL, a description of the NLSL, and how the NLSL shall be served. If BPA serves the NLSL, Contracted Power will be provided under the NR rate schedule unless the Parties agree to service under a surplus rate schedule, and establishes rates and billing factors in Exhibit D, Additional Products and Special Provisions.)

[OPTIONS for section 3(a).
Option 1-Include the following if customer has no existing NLSL.
(a) «Customer Name» has no existing NLSL.

Option 2-Include the following if customer has an existing NLSL. The load listed may no longer be considered to be a NLSL if BPA establishes a new NLSL policy (i.e., Klickitat, Goldendale). This should be noted and the right to change the determination should be established.
(a) «Customer Name» has an existing NLSL. The NLSL is listed below.
End of OPTIONS for section 3(a).]

(b) «Customer Name» shall serve any NLSLs with resource amounts added consistent with section 4 of Exhibit C, Net Requirements. When «Customer Name» has a NLSL this exhibit shall be revised to include estimated monthly HLH and LLH MWs in a table below.

4. REVISIONS*(06/27/00 Version)*

The Parties may update this exhibit by mutual agreement.

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Exhibit B
BILLING

1. NEW RESOURCE FIRM POWER ENTITLEMENTS*(04/27/00 Version)*

(a) The HLH and LLH amounts shown in section 5(b) of the body of this Agreement multiplied by the number of hours in an applicable daily Diurnal period establishes «Customer Name»'s daily NR HLH and LLH Energy Entitlements.

(b) The HLH amount shown in section 5(b) of the body of this Agreement establishes «Customer Name»'s NR Demand Entitlement.

2. DEFINITIONS*(04/27/00 Version)*

"Deemed Schedule" means the greater of the scheduled amount or the minimum hourly purchase amount established in section 5 of the body of this Agreement.

3. HOURLY ENERGY TEST*(04/27/00 Version)*

(a) The Unauthorized Increase Charge for energy shall be applied to the portion of the Deemed Schedule that exceeds the NR Demand Entitlement.

(b) For LLH, the Unauthorized Increase Charge for energy shall be applied to the portion of the Deemed Schedule that exceeds the amounts shown, for LLH in section 5(b) of the body of this Agreement. The minimum hourly LLH purchase obligation is the amount shown in section 5(b) of the body of this Agreement.

(c) Amounts Taken in excess of the Deemed Schedules are subject to the Unauthorized Increase Charge.

4. DAILY ENERGY TEST*(04/27/00 Version)*

The Unauthorized Increase Charge for energy shall be applied to the portion of the total daily HLH Deemed Schedules from PBL that exceeds the daily NR HLH Energy Entitlement, less any energy that is subject to the Unauthorized Increase Charge as determined under section 3(a) of this exhibit. «Customer Name»'s minimum daily HLH energy purchase obligation is the «Customer Name»'s NR HLH Energy Entitlement.

5. MONTHLY DEMAND TEST*(04/27/00 Version)*

The Unauthorized Increase Charge for demand shall be applied to the amount by which the largest Amounts Taken or Deemed Schedule on any HLH during the month exceeds the NR Demand Entitlement.

6. NLSL POWER ENTITLEMENTS*(04/27/00 Version)*

(a) The amount of energy served by PBL under section 3 of Exhibit A during each applicable Diurnal period establishes «Customer Name»'s Monthly NR HLH and LLH Energy Entitlements for NLSLs.

(b) The amount of demand served by PBL under section 3 of Exhibit A that is made available on Generation System Peak is «Customer Name»'s Measured Demand for NLSLs.

7. **UNAUTHORIZED INCREASE CHARGE*(04/27/00 Version)***
Amounts Taken from PBL in excess of Firm Power shall be subject to the Unauthorized Increase Charge for demand and energy consistent with the applicable BPA Wholesale Power Rate Schedules and GRSPs, unless such power is provided under another contract with PBL. Power that has been provided for energy imbalance service pursuant to an agreement between TBL and «Customer Name» will not be subject to an Unauthorized Increase Charge for Demand and Energy under this Agreement.

8. **REVISIONS*(06/27/00 Version)***
This exhibit may be revised upon mutual agreement by the Parties.

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Exhibit C
NET REQUIREMENTS

1. ESTABLISHING NET REQUIREMENT

(a) Initial Net Requirement

(1) **Total Retail Load Forecast*(04/27/00 Version)***
The tables below shows the PBL approved forecast of «Customer Name»'s Total Retail Load. The Parties agree that this forecast shall not be subject to arbitration under section 15 of the body of this Agreement.

Total Retail Load												
Contract Year	**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sept**
Total MWh												
HLH (MWh)												
LLH (MWh)												
Peak (MW)												

(2) **Initial Net Requirement*(04/27/00 Version)***
«Customer Name»'s net requirement amounts are derived by taking the forecast of «Customer Name»'s Total Retail Load and subtracting from it the resource amounts that are committed to serve «Customer Name»'s Total Retail Load under section 2(c) of this exhibit and the amount of load served by known non-«Customer Name» resources, if any, as established in section 3 of this exhibit.

NET REQUIREMENTS												
Contract Year	**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sept**
Total MWh												
HLH (MWh)												
LLH (MWh)												
Peak (MW)												

(b) Annual Update of Net Requirement

(1) **Updated Forecast of Total Retail Load*(06/09/00 Version)***
At least 60 days prior to the start of each Contract Year, «Customer Name» shall provide PBL an updated monthly forecast of «Customer Name»'s Total Retail Load in sufficient detail to fill in the table below. Up to 30 days before the start of the Contract Year PBL may notify «Customer Name» that PBL has determined that the forecast submitted when considered as a whole is not reasonable and that PBL will substitute a forecast of Total Retail Load that it considers reasonable to fill in the table below. The only issue arising under this

section 1(b)(1) that is subject to arbitration under section 15 of body of this Agreement is whether PBL's forecast when considered as a whole was reasonable. Such arbitration shall not include the interpretation or application of BPA's policies to such load forecast. However the Parties may mutually agree to mediate disputes regarding PBL's forecast. Prior to the start of the Contract Year this exhibit shall be revised to update the forecast in the table below.

Total Retail Load												
Contract Year	**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sept**
Total MWh												
HLH (MWh)												
LLH (MWh)												
Peak (MW)												

(2) **Review of Net Requirements Amounts*(04/27/00 Version)***
«Customer Name»'s updated net requirement amounts are derived by taking the «Customer Name» forecast of Total Retail Load established in section 1(b)(1) above and subtracting from it the resource amounts that are committed to serve «Customer Name»'s Total Retail Load under section 2(c) and the amount of load served by known non-«Customer Name» resources, if any, as established in section 3 of this exhibit. The updated net requirement amounts shall be shown in the table below.

NET REQUIREMENTS												
Contract Year	**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sept**
Total MWh												
HLH (MWh)												
LLH (MWh)												
Peak (MW)												

2. CUSTOMER RESOURCES*(04/27/00 Version)*

The amounts listed in the tables in this section are only for determining «Customer Name»'s net requirement under this Agreement and do not imply any specific resource operation, nor are the amounts intended to interfere with «Customer Name»'s decisions on how to operate its specific resources.

(a) **Declared Output of Specific «Customer Name» Resources*(04/27/00 Version)***
«Customer Name» commits the firm output from the following resources (or an equivalent amount from another source) to serve its Total Retail Load.

(1) **Resource Name*(04/27/00 Version, modified by CLT3737 on 10/23/00)***
«Customer Name»'s resources and the characteristics of the resources are identified in the chart below. Power amounts associated with resources are listed in the attachment to this exhibit. The column labeled "Table" in the chart below corresponds to the tables listed in the attachment.

Table	Resource Name	Resource Type	5b1A/ 5b1B	Number of Units	Peak Cap MW	Customer % Share	% Ded to TRL	Resource Addition

(b) **Unspecified Resource Amounts Committed To Serve Total Retail Load*(04/27/00 Version)***
«Customer Name» shall use its best efforts to meet the obligations to provide unspecified resources established in the provisions below. «Customer Name» agrees that if such power is acquired from PBL as anything other than a separately negotiated purchase of Surplus Firm Power, the power provided will be subject to the Unauthorized Increase Charge.

(1) **Unspecified Resources for Balancing Net Requirements*(06/09/00 Version)***
«Customer Name» agrees to provide power from unspecified resources to serve Total Retail Load in amounts, and in periods, equal to its Total Retail Load not served through «Customer Name»'s power purchases committed to load under this Agreement, through resource amounts committed in section 2(a) above, through unspecified resource amounts established in sections 2(b)(2) and 2(b)(3) below, or through amounts in section 3 below. The amount in the table below shall be updated annually to show the amount, if any that the forecast established in section 1(b)(1) of this exhibit exceeds the sum of the following: the power amount established in section 4 of the body of this exhibit(as updated consistent with section 5 of this exhibit); and resource amounts committed for the upcoming Contract Year in sections 2(a), 2(b)(2), 2(b)(3), and 3 of this exhibit.

Contract Year	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sept
Total MWh												
HLH (MWh)												
LLH (MWh)												

(2) **Specific Amounts Committed for Contract Term*(04/27/00 Version)***

In addition to the resource amounts established in section 2(a) above «Customer Name» agrees to serve its Total Retail Load with unspecified resources in the amounts listed in the table below.

None at this time.

(3) **Amounts Committed for 9(c) Decrements*(04/27/00 Version)*** Below are the amounts of unspecified resources added consistent with BPA's 9(c) Policy and the requirements of section 4(c) of this exhibit.

None at this time.

(c) **Total Resource Amounts Committed to Serve Total Retail Load*(04/27/00 Version)***
«Customer Name» commits the resources listed in sections 2(a) and 2(b) above to serve Total Retail Load amounts served by «Customer Name» and not served with Firm Power through this Agreement. The total amount of «Customer Name»'s resources are shown in the table below. These amounts shall be updated whenever sections 2(a) or 2(b) above are modified, consistent with section 4 of this exhibit.

Sum of Resources												
Contract Year	**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sept**
Total MWh												
HLH (MWh)												
LLH (MWh)												
Peak (MW)												

(d) **«Customer Name» Resource Not Used to Serve Total Retail Load*(04/27/00 Version)***

Generating Resource Name	Resource Type	5b1A/ 5b1B	Number of Units	Peak Cap MW	Customer % Share	% Ded to TRL	Resource Addition

Contract Year	**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sept**
Total (MWh)												
HLH (MWh)												
LLH (MWh)												
Peak (MW)												

3. **NON-«CUSTOMER NAME» GENERATING RESOURCES*(06/09/00 Version)***
Known non-«Customer Name» resources greater, if any, than 1 MW that provide power to serve «Customer Name»'s Total Retail Load or such resources that otherwise connect to «Customer Name»'s distribution system are listed below.

Generating Resource Name	Resource Type	Nameplate Capability

The amounts in the table below establish the total amount of non-«Customer Name» resources that the Parties agree are to be applied to serve «Customer Name»'s Total Retail Load to calculate «Customer Name»'s net requirement. These amounts may only be modified consistent with section 4 of this exhibit.

Contract Year	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sept
Total (MWh)	0	0	0	0	0	0	0	0	0	0	0	0
HLH (MWh)	0	0	0	0	0	0	0	0	0	0	0	0
LLH (MWh)	0	0	0	0	0	0	0	0	0	0	0	0
Peak (MW)	0	0	0	0	0	0	0	0	0	0	0	0

4. CHANGES TO RESOURCE AMOUNTS

(a) **Annual Right to Add New Renewable Resources*****(04/27/00 Version)***
«Customer Name» may add new renewable resources to section 2(a) of this exhibit according to the terms of this provision. «Customer Name» shall request the addition of such resources at least 60 days before the start of the Contract Year the resources will be added. The request shall identify the resources, the length of time that the resources shall be applied to «Customer Name»'s Total Retail Load and power amounts from the resources for each month of the request. PBL will revise section 2 of this exhibit prior to the start of the Contract Year if PBL agrees that the resource meets BPA's standards to qualify for BPA's Conservation and Renewables Discount, subject to any applicable limits established in BPA's policy on net requirements under section 5(b) of the Northwest Power Act. «Customer Name» shall resume purchasing Firm Power under this Agreement when its commitment to apply the renewable resource ends. The rate treatment for such power shall be the same «Customer Name» would have received for such power if «Customer Name» had not chosen to apply a resource under this provision.

(b) **Resource Additions for a BPA Insufficiency Notice*****(04/27/00 Version)***
In lieu of the unspecified resource amounts established in 2(b)(1), «Customer Name» shall add resources to sections 2(a) or 2(b)(2) to replace amounts of Firm Power BPA notifies «Customer Name» will not be provided due to a notice under section 16(b) of the body of this Agreement.

(c) **Decrements for 9(c) Export*****(06/27/00 Version)***
PBL may determine consistent with BPA's policy implementing section 9(c) of the Northwest Power Act and section 3(d) of P.L. 88-552 (9(c) Policy) that an export of a «Customer Name» resource requires a reduction in the amount of Federal power that PBL sells under this Agreement. If PBL determines such a reduction is required it will notify «Customer Name» of the amount and

duration of the reduction. PBL shall revise this exhibit to include such amounts as unspecified resources for the duration of the export requiring such reduction under section 2(b)(3). Determinations by PBL to reduce the amount of Federal power sold are not subject to arbitration under section 14 of the body of this Agreement. When a decrement under the BPA 9(c) Policy occurs within the Contract Year, (1) the monthly amounts in 1(b)(2) shall be reduced by how much the monthly amounts added to 2(b)(3) exceed the corresponding monthly amounts in 2(b)(1), and (2) the Firm Power provided by PBL shall also be reduced within the Contract Year consistent with such changes to 1(b)(2), through the terms of section 5 below.

(d) **Permanent Resource Removal*(04/27/00 Version)***
The resource amounts established in section 2 of this exhibit may be removed permanently by «Customer Name» consistent with statutory discontinuance for permanent removal in BPA's policy on net requirements under section 5(b) of the Northwest Power Act. If PBL determines «Customer Name» has met PBL's standards for a permanent removal, the exhibit will be revised to show the agreed resource changes. Additional power purchases under this Agreement as a result of such a resource removal are subject to the terms established in section 4(d) of Exhibit A, Rate Commitments. Determinations by PBL on the permanent removal of a resource are not subject to arbitration under section 15 of the body of this Agreement.

(e) **Changes to Non-«Customer Name» Resources*(04/27/00 Version)***
«Customer Name» shall annually update the information established for non-«Customer Name» resources in section 3 at least 60 days before the start of each Contract Year, if circumstances reasonably warrant such a change. Subject to agreement of the Parties, the exhibit shall be revised to show the updated information prior to the start of the applicable Contract Year.

(f) **Resource Additions for NLSL and Annexed Loads*(04/27/00 Version)***
In lieu of the unspecified resource amounts established in section 2(b)(1), «Customer Name» may add an amount of resources to sections 2(a) or 2(b)(2) above to serve the full amount of Annexed Loads established in Exhibit A, Rate Commitments and NLSLs added after this Agreement is executed.

(g) **Annual Retail Load Loss and Resource Removal*(04/27/00 Version)***
«Customer Name» may reduce the resource amounts established in sections 2(a) and 2(b) above by up to the amount of load loss «Customer Name» reasonably expects in the upcoming Contract Year consistent with the requirements of this section. «Customer Name» shall notify PBL at least 60 days prior to the applicable Contract Year, identifying the total monthly Diurnal MWh amounts of load loss. Reductions in resource amounts shall apply first to unspecified resources established in sections 2(b)(1) and 2(b)(2) of this exhibit. Additional reductions shall apply to specific resources in section 2(a) of this exhibit identified by «Customer Name» in the notice. The Parties shall revise this exhibit prior to the start of the Contract Year to make the changes in the resources and shall establish those changes in tables

below which shall identify the specific changes that were made to the resources. The resource changes shall only apply for one Contract Year. Prior to the start of the subsequent Contract Year this exhibit shall be revised to add back the resources shown in tables below to the applicable provisions in section 2 of this exhibit, except for amounts «Customer Name» requests to remove under this provision for the following Contract Year. Resources removed under this provision continue to be subject to the 9(c) Policy.

(h) **Revisions for Changes in Resource Output*(09/05/00 Version)***
Up to 60 days prior to the start of a Contract Year «Customer Name» may request changes to the monthly distribution of the capabilities of specific resources listed in section 2 of this exhibit. «Customer Name» must demonstrate to PBL's satisfaction that an adjustment is appropriate. PBL will only consider such adjustments within like diurnal periods. When PBL decides to grant a request to revise resource amounts PBL shall revise section 2 of this exhibit to show the changes to the resource. Any increase in purchases under this Agreement because of such a reduction in a resource shall be subject to section 4(d) of Exhibit A.

5. REDUCTION OF BLOCK PURCHASE AMOUNTS*(09/05/00 Version)*
The monthly amounts of Firm Power provided under this Agreement shall be reduced in any month when the monthly net requirement amount established in section 1(b)(2) above is less than the corresponding monthly amount established in section 5 of the body of this Agreement. The reduction shall equal the difference between those monthly values. The monthly amounts shall also be reduced when resource amounts not already used to calculate the monthly values in section 1(b)(2) are added pursuant to section 4(c) above during the Contract Year. Reduced amounts are subject to payments as established in section 5 of the body of this Agreement. If such a reduction occurs this exhibit will be revised to include a table below with the updated values. The amounts in the table may be increased under the terms established in section 4(c) of Exhibit A. When a table is included below it shall supersede the table in section 5 of the body of this Agreement.

6. RESOURCE DECLARATIONS*(06/09/00 Version)*
The resource capabilities set forth in sections 2(a) and (b) of this exhibit are dedicated to serving «Customer Name»'s firm load pursuant to section 5(b) of the Northwest Power Act. In addition to the resource capabilities set forth in such sections that may be removed pursuant to other sections of this Agreement, BPA consents that the resource capabilities set forth in section 2(b)(1) and (2) above may be discontinued from use in serving «Customer Name»'s firm load upon the termination or expiration of this Agreement. The resources established in sections 2(d) and 3 above are not used to serve «Customer Name»'s firm load under section 5(b) of the Northwest Power Act and will not be required to be so used after the termination or expiration of this Agreement.

7. REVISIONS*(04/27/00 Version)*

When required «Customer Name» shall submit a revised Exhibit C, Net Requirements, to PBL at least 60 days prior to each Contract Year. As long as «Customer Name»'s submittal is consistent with the requirements of this exhibit PBL shall accept it as submitted. If «Customer Name» fails to submit revisions when necessary, or if the information provided is inconsistent with the requirements of this exhibit, PBL shall update this exhibit prior to the beginning of the Contract Year with the information PBL believes is required.

ATTACHMENT

Table 1:												
Contract Year	**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sept**
Total (MWh)												
HLH (MWh)												
LLH (MWh)												
Peak (MW)												

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Exhibit D
ADDITIONAL PRODUCTS AND SPECIAL PROVISIONS

1. (NO SPECIAL PROVISIONS AT THIS TIME.)

2. REVISIONS*(04/27/00 Version)*
This exhibit shall be revised by mutual agreement of the Parties to reflect additional products and/or special provisions during the term of this Agreement.

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Exhibit E
SCHEDULING

1. **PURPOSE OF THIS EXHIBIT*(04/27/00 Version)***
The purpose of this exhibit is to identify power scheduling requirements and coordination procedures necessary for the delivery of electric power and energy sold under this Agreement. All provisions apply to Purchasing-Selling Entities (PSEs), including their authorized scheduling agent. Transmission scheduling arrangements are handled under separate agreements/provisions with the designated transmission provider. Nothing in this exhibit is intended to relieve the Parties of any obligation they may have under North American Electric Reliability Council (NERC) or Western Systems Coordinating Council (WSCC) policy, procedure, or guideline.

2. **COORDINATION: GENERAL, PRESCHEDULE, REAL-TIME, AND AFTER-THE-FACT REQUIREMENTS*(04/27/00 Version)***

(a) **General Requirements**

(1) The Parties may revise and replace this exhibit by mutual agreement. BPA shall also have the right to revise and replace this exhibit under the following circumstances after providing an opportunity for all affected Parties to discuss and comment on any proposed changes: (1) to comply with rules or orders issued by FERC, NERC, or WSCC; or (2) to implement changes reasonably consistent with standard industry practice, but necessary for BPA to administer its power scheduling function.

(2) PSEs shall have staff available 24 hours a day for each day an active transaction or preschedule is in effect. PSE's must be prepared to verify transactions on an hourly basis if necessary.

(3) PSEs shall complete the prescheduling and check out processes, and to verify Transactions and associated totals, per NERC tag, and BPA contract.

(4) Inability to verify Transactions may result in schedule rejection or curtailment.

(5) PSEs shall verify Transactions and totals after-the-fact (ATF) per both parties' ATF processes.

(6) BPA is not obligated to accept Transactions that do not comply with the scheduling requirements in this exhibit or the contract.

(7) Should a PSE attempt to preschedule a Transaction for power for which that PSE has an obligation to provide transmission and fails to properly reserve the transmission necessary to complete the

Transaction, the PSE will not be excused from its payment obligation, if any, under this Agreement.

(8) All Transactions shall be stated in the time zone specified by WSCC and shall be in "hour-ending" format.

(9) All Schedules, except Dynamic Schedules, will be implemented on an hourly basis using the standard ramp as specified by WSCC procedures.

(10) Any power that is allowed to be resold at wholesale under this Agreement may only be resold if all characteristics of the product (e.g., Points of Receipt, shape, hours) are maintained in the resale.

(11) Changes to telephone or fax numbers of key personnel (for Prescheduling, Real-Time, Control Area, or Scheduling Agents, etc.) must be submitted to BPA.

(b) **Prescheduling Requirements**

(1) **Information Required for Any Preschedule**

(A) Unless otherwise mutually agreed, all Transactions will be submitted according to NERC instructions for E-tagging, as modified by WSCC.

(B) When completing the NERC E-Tag insert the applicable BPA Contract number(s) in the "reference" column of the miscellaneous section of the tag.

(C) Transactions going to or from California-Oregon Border (COB) must be identified as using Malin or Captain Jack, or COB Hub.

(2) **Preschedule Coordination**

(A) Final hourly preschedules (verbal submission of E-tag information) must be submitted for the next day(s) by 1000 of each Workday, unless otherwise agreed.

(B) Typically, preschedules are for one to three days. By mutual agreement of the parties, final preschedules may be requested for longer time periods to accommodate special scheduling requirements.

(C) Under certain operating conditions, either party may require submission of estimated daily preschedules for an ensuing period up to ten days in length, prior to the final preschedule.

(c) **Real-Time Requirements**

(1) PSEs may not make Real-Time changes to the scheduled amounts, including transmission arrangements unless such changes are allowed under individual contract provisions or by mutual agreement.

(2) If Real-Time changes to the Schedule become necessary, and are allowable as described in section 2(c)(1) above, PSEs must submit such request no later than 30 minutes prior to the hour for which the Schedule change becomes effective.

(3) Multihour changes to the Schedule shall specify each hour to be changed and shall not be stated as "until further notice."

(4) Emergency scheduling and notification procedures (including mid-hour changes) will be handled in accordance with NERC and WSCC procedures.

(d) **After-the-Fact Reconciliation Requirements**
PSEs agree to reconcile all Transactions, Schedules and accounts at the end of each month (as early as possible within the first 10 calendar days of the next month). The parties will verify all Transactions per BPA contract, as to product or type of service, hourly amounts, daily and monthly totals, and related charges.

3. DEFINITIONS AND ACRONYMS*(04/27/00 Version)*
Capitalized terms in this Exhibit shall have the meanings defined below, in context, or as used elsewhere in this Agreement.

(a) **Control Area:** An electrical system bounded by interconnection (tie-line) metering and telemetry. It controls generation directly to maintain its interchange schedule with other control areas and contributes to frequency regulation of the interconnection.

(b) **Hour Ending**: Designation for one hour periods of time based upon the time which the period ends. For example: the one hour period between 1300 and 1400 is referred to as Hour Ending 1400.

(c) **Prescheduling:** The process (electronic, oral, and written) of establishing and verifying with all scheduling parties, advance hourly Transactions through the following Workday(s). Preschedules apply to the following day or days (if the following day or days are not Workday(s).

(d) **Purchasing-Selling Entity (PSE):** (NERC defined term). An entity that is eligible to purchase or sell energy or capacity and reserve transmission services.

(e) **Real-Time:** The hourly or minute-to-minute operation and scheduling of a power system as opposed to those operations which are prescheduled a day or more in advance.

(f) **Schedule:** The planned Transaction approved and accepted by all PSEs and Control Areas involved in the Transaction.

(g) **Transaction:** An agreement arranged by a PSE to transfer energy from a seller to a buyer.

(h) **Workday:** Any day BPA, other regional utilities, and PSEs observe as a working day.

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Contract No. 09PB-«#####»

Reviewers Note: Language in the Publics' PF Block template involving tiered rates, TRM, PF, etc. is not applicable and has been removed from the IOU NR Block Template.

DRAFT NR Block Template

POWER SALES AGREEMENT

executed by the

BONNEVILLE POWER ADMINISTRATION

and

«FULL NAME OF CUSTOMER»

Table of Contents

This POWER SALES AGREEMENT (Agreement) is executed by the UNITED STATES OF AMERICA, Department of Energy, acting by and through the BONNEVILLE POWER ADMINISTRATION (BPA), and «FULL NAME OF CUSTOMER» («Customer Name»), collectively referred to as the "Parties". «Customer Name» is an investor-owned utility organized under the laws of the State of «____________________», to serve retail consumer load from its distribution system within its service area.

RECITALS *(02/28/08 Version Revised 03/03/2008 for RPSA)*

This Agreement will replace «Customer Name»'s current power sales agreement (Contract No. «##PB-#####») which continues through September 30, 2011.

BPA has functionally separated its organization in order to functionally separate the administration and decision-making activities of BPA's power and transmission functions. References in this Agreement to Power Services or Transmission Services are solely for the purpose of clarifying which BPA function is responsible for administrative activities that are jointly performed.

The Parties agree:

1. **TERM** *(02/28/08 Version Revised 03/03/2008 for NR Block. Language regarding HWM removed.)*
This Agreement takes effect on the date signed by the Parties and expires on September 30, 2028. Performance by BPA and «Customer Name» shall commence on October 1, 2011, with the exception of those actions required prior to that date that are included in section 11, Information Exchange and Confidentiality; Exhibit A, Net Requirements.

2. **DEFINITIONS** *(02/28/08 Version)*
Capitalized terms below shall have the meaning stated. Capitalized terms that are not listed below are either defined within the section in which the term is used or, if not so defined, shall have the meaning stated in BPA's applicable Wholesale Power Rate Schedules, including the General Rate Schedule Provisions (GRSPs).

(a) "Annexed Load"*(04/04/08 Version)* means existing load and distribution system, and/or service territory «Customer Name» acquires from another utility, by means of annexation, merger, purchase or trade, and authorized by a final state regulatory or court action, for which «Customer Name» has the right or has obtained an ownership interest in the facilities necessary to serve the load.

.(b) "Contract Resources"*(02/29/08 Version)* means sources or amounts of electric power that «Customer Name» acquires from unidentified electricity-producing units by contract purchase from an electricity supplier.

(c) "Firm Requirements Power"*(02/28/08 Version)* means federal power that is sold under this Agreement and made continuously available, except for an Uncontrollable Force, to meet BPA's load obligations under section 5(b) of the Northwest Power Act.

(d) "Fiscal Year" or "FY"*(02/28/08 Version)* means the period beginning each October 1 and ending the following September 30.

(e) "Generating Resources"*(02/29/08 Version)* means sources or amounts of electric power from identified electricity-producing units owned by, or of which a share is owned by, «Customer Name» or «Customer Name»'s retail consumer.

(f) "Interchange Points"*(04/01/08 Version)* means the points where Balancing Authority Areas interconnect, and at which the interchange of energy between Balancing Authority Areas is monitored and measured.

(g) "New Large Single Load" or "NLSL"*(02/28/08 Version)* means a large single load as defined in section 3(13) of the Northwest Power Act and in BPA's NLSL policy.

(h) "Points of Delivery" or "POD"*(03/01/08 Version)* means the points where power is transferred from a transmission provider to «Customer Name».

(i) "Points of Metering" or "POM"*(10/15/07 Version)* means the points at which power is measured.

(j) "Power Services"*(09/04/07 Version)* means the organization, or its successor organization, within BPA that is responsible for the management and sale of federal power from the Federal Columbia River Power System.

(k) "Region"*(09/04/07 Version)* means the Pacific Northwest as defined in the Northwest Power Act.

(l) "Specified Resources"*(04/04/08 Version)* means a Generating Resource or a Contract Resource which «Customer Name» has dedicated to serve its Total Retail Load that is ascribed to a particular non-federal resource.

Reviewer's Note: The following definition is close, but not identical to the TRM's definition. We will reconcile these.

(m) "Total Retail Load"*(04/04/08 Version)* means all retail electric power consumption, including electric system losses, within «Customer Name»'s electrical system excluding:

(1) unmetered loads or generation,

(2) nonfirm or interruptible loads agreed to by the Parties,

(3) transfer loads of other utilities served by «Customer Name», and

(4) any loads not on «Customer Name»'s distribution system that are not agreed to by BPA.

(n) "Transmission Services"*(09/04/07 Version)* means the organization, or its successor organization, within BPA that is responsible for the management and sale of transmission service on the Federal Columbia River Transmission System.

(o) "Unspecified Resource Amounts"*(03/21/08 Version)* means an amount of firm power «Customer Name» has agreed to supply and dedicate to serve its Total Retail Load that is not ascribed to a particular Generating Resource or Contract Resource.

3. BLOCK POWER PURCHASE OBLIGATION *(03/03/2008 Version for NR Block)*

(a) **Purchase and Sale of Block Product**
Subject to section 3(b) below, BPA shall sell and make available, and «Customer Name» shall purchase, Firm Requirements Power each hour in planned amounts based on «Customer Name»'s forecasted Total Retail Load minus the monthly firm energy and peaking output from each of «Customer Name» and non-«Customer Name» resources used to serve such Total Retail Load, as listed in Exhibit A, Net Requirements. «Customer Name» agrees to serve any portion of its Total Retail Load that is not served with Firm Requirements Power with the non-federal resources identified in Exhibit A, Net Requirements.

(b) **Establishment of Block Power Amounts**

(1) **Provisions Related to Delivery**
Firm Requirements Power shall be made available to «Customer Name» as a flat annual block, which delivers an equal amount of firm Requirements Power in all hours of each month for each FY.

(2) **Notice Deadlines and Purchase Periods**
Notice Deadlines and corresponding Purchase Periods are as follows:

Notice Deadline	Purchase Period

(3) **Short-Term Rate Purchases**
By each Notice Deadline above, «Customer Name» shall provide written notice to BPA of «Customer Name»'s purchase amounts (including zero amounts) of Firm Requirements Power priced at the NR Rate for each year of the corresponding Purchase Period. If «Customer Name» does not provide such notice, «Customer Name» shall purchase zero amounts of Firm Requirements Power priced at the NR Rate for the corresponding Purchase Period. BPA and «Customer Name» shall amend this Agreement in order to update the table below to show «Customer Name»'s purchase amounts.

Purchase Amounts

Fiscal Year	2012	2013	2014	2015	2016	2017	2018	2019
aMW								

Fiscal Year	2020	2021	2022	2023	2024	2025	2026	2027	2028
aMW									

4. **APPLICABLE RATES** *(02/28/08 Version Revised 03/17/2008 for NR Block)*
Purchases under this Agreement are subject to the New Resource Firm Power (NR) rate schedule. Purchases are also subject to the General Rate Schedule Provisions (GRSPs), or their successors.

(a) **New Resource Firm Power Rates**
BPA shall establish its NR power rates that apply to purchases under this Agreement pursuant to section 7 of the Northwest Power Act.

(b) **New Large Single Loads** *(02/28/08 Version)*
Any amounts of power provided to «Customer Name» for service to an NLSL shall be sold at the NR rate as listed in Exhibit B, Additional Products and Special Provisions.

(c) **Additional Charges** *(02/28/08 Version, revised 3/17/08 for NR Block)*
«Customer Name» may be subject to any additional charges in the GRSPs, including the Unauthorized Increase (UAI) Charge.

5. **TAKE OR PAY** *(02/08/08 Version Revised 03/03/2008 for NR Block)*
«Customer Name» shall pay for the amount of power it commits to purchase, if any, under section 3 of this Agreement, at the rates BPA establishes as applicable to such power, whether or not «Customer Name» took delivery of such power.

6. **NO WARRANTY** *(03/26/08 Version)*
Reviewer's Note: This section is based on the Regional Dialogue Policy (page 52, section XI, Dispute Resolution)

Nothing in this Agreement, or any dispute arising out of this Agreement, shall limit the Administrator's responsibility to establish rates to recover costs and timely repay the U.S. Treasury or to take actions that are effectively required by a court order. It is the Parties' intent to structure a durable commercial relationship that is based on existing statutory requirements and to provide «Customer Name» with protection against change to those guiding statutes as is reasonably possible. However, BPA does not warrant or represent that this Agreement is immune from costs imposed by court order or agency regulations of a general and public nature or is immune from subsequently enacted legislation.

7. SCHEDULING *(09/04/07 Version)*
«Customer Name» shall schedule power in accordance with Exhibit C, Scheduling.

8. DELIVERY

(a) **Definitions**

(1) "Integrated Network Segment" *(03/17/08 Version)*means those facilities of the Federal Columbia River Transmission System that are required for the delivery of bulk power supplies, the costs for which are recovered through generally applicable rates, and that are identified as facilities in the Integrated Network Segment, or its successor, in the BPA segmentation study for the applicable transmission rate period as determined in a hearing establishing or revising BPA's transmission rates pursuant to section 7(i) of the Northwest Power Act.

(2) "Primary Points of Receipt" *(03/17/08 Version)*means the points on the Pacific Northwest transmission system where Firm Requirements Power is forecasted to be made available by Power Services to «Customer Name» for purposes of obtaining a long-term firm transmission contract.

(3) "Scheduling Points of Receipt" *(03/17/08 Version)*means the points on the Pacific Northwest transmission system where Firm Requirements Power is made available by Power Services to «Customer Name» for purposes of transmission scheduling.

(b) **Transmission Service** *(03/17/08 Version)*

(1) «Customer Name» is responsible for delivery of power from the Scheduling Points of Receipt.

(2) «Customer Name» shall provide at least 60 days' notice to Power Services prior to changing Balancing Authority Areas.

(3) At «Customer Name»'s request, BPA shall provide «Customer Name» with Primary Points of Receipt and other information needed to enable «Customer Name» to obtain long-term firm transmission for

delivery of power sold under this Agreement. If required by Transmission Services for purposes of transmission scheduling, Power Services shall provide «Customer Name» with Scheduling Points of Receipt. Power Services has the right to provide power to «Customer Name» at Scheduling Points of Receipt that are different than the Primary Points of Receipt. If BPA does provide power to «Customer Name» at Scheduling Points of Receipt that are different than the Primary Points of Receipt, then BPA shall reimburse «Customer Name» for any incremental, direct, non-administrative costs incurred by «Customer Name» to comply with delivering Firm Requirements Power from such a Scheduling Point of Receipt to «Customer Name»'s load if the following conditions, as outlined, have been met:

(A) «Customer Name» has requested long-term firm transmission service to deliver its Firm Requirements Power using the Primary Points of Receipt and other information provided by Power Services; and,

(B) This condition only applies if «Customer Name» has long-term Point to Point (PTP) transmission service (as defined in BPA's Open Access Transmission Tariff) for delivery of Firm Requirements Power to its load: «Customer Name» has submitted a request to redirect its long-term firm PTP transmission service to deliver Firm Requirements Power from the Scheduling Point of Receipt on a firm basis, but that request was not granted; and

(C) «Customer Name»'s transmission schedule was curtailed due to non-firm status under PTP transmission service or its secondary service status under Network Integration transmission service (as defined in BPA's Open Access Transmission Tariff) and «Customer Name» can provide proof of the reimbursable costs incurred to replace the curtailed schedule.

(c) **Liability for Delivery***(03/13/08 Version)*
«Customer Name» waives any claims against BPA arising under this Agreement for nondelivery of power to any points beyond the applicable Scheduling Points of Receipt, except as described in section 8(b)(3) above. BPA shall not be liable for any third-party claims related to the delivery of power after it leaves the Scheduling Points of Receipt. In no event will either Party be liable under this Agreement to the other Party for damage that results from any sudden, unexpected, changed, or abnormal electrical condition occurring in or on any electric system, regardless of ownership. These limitations on liability apply regardless of whether or not this Agreement provides for transfer service.

(d) **Real Power Losses** *(03/14/08 Version)*
BPA is responsible for the real power losses necessary to deliver Firm Requirements Power to «Customer Name»'s Points of Delivery (PODs) listed in Exhibit D, Metering.

(e) **Points of Metering Losses** *(04/03/08 Version)*
BPA shall adjust measured amounts of power to account for losses, if any, that occur between «Customer Name»'s PODs and the respective Points of Metering (POMs).

9. METERING *(03/31/08 Version)*

(a) **Scheduling and Metering**
«Customer Name» shall pay for the amount of power it schedules under this Agreement, except when the Parties agree that scheduling is economically or technologically impractical for a particular situation. In these cases, «Customer Name» shall pay for and install metering equipment that meets American National Standard Institute standards, including, but not limited to, C12.20, Electricity Meters—0.2 and 0.5 Accuracy Classes and the Institute of Electrical and Electronics Engineers, Inc. standard C57.13, Requirements for Instrument Transformers, or their successors.

Reviewer's Note: The Meter Usage Data Estimations provision of GRSPs will be developed prior to 2011, these provisions are currently contained in BPA billing procedures.
If the metering equipment associated with the meters listed in Exhibit D, Metering, fails to properly measure or record the interval readings, BPA will apply the procedure set out in the Meter Usage Data Estimations provision of the GRSPs to determine the appropriate billing adjustment.

(b) **Non-BPA Owned Meters**
For all non-BPA metering equipment owned by «Customer Name» that is needed by BPA to forecast, plan, schedule, and bill for power «Customer Name» shall give BPA direct, electronic access to meter data from all meters not owned by BPA that are capable of being accessed electronically. For the purpose of inspection, «Customer Name» shall grant BPA physical access to «Customer Name»'s meters at BPA's request.

BPA has the right to witness any meter tests conducted by «Customer Name» on non-BPA owned meters listed in Exhibit D and, with advance notice, BPA may conduct tests on such meters.

If, at any time, BPA or «Customer Name» determines that a «Customer Name»-owned meter listed in Exhibit D, Metering is defective or inaccurate, «Customer Name» shall adjust, repair, or replace the meter to provide accurate metering as soon as practical. «Customer Name» shall operate, maintain, and replace, as necessary at «Customer Name» expense, all non-BPA metering equipment owned by «Customer Name». For non-BPA owned meters listed in Exhibit D, Metering that are not owned by «Customer Name» but are needed by BPA to forecast, plan, schedule and bill for power, «Customer Name» shall arrange for such meters to be operated, maintained and replaced, as necessary.

(c) **New Meters**
«Customer Name» and BPA shall enter into a separate agreement addressing the ownership, cost responsibility, location, access, maintenance, replacement, testing, and liability of the Parties with respect to new meters. For the purpose of implementing this provision, «Customer Name» shall grant BPA physical access to BPA owned meters at BPA's request.

(d) **Metering an NLSL**
«Customer Name» shall comply with and administer the metering of NLSLs, and for any large consumer loads for which BPA requests monitoring in aid of an NLSL determination, consistent with section 15(c)(4), Metering an NLSL.

(e) **Metering Exhibit and Revisions**
«Customer Name»shall provide meter data specified in section 11(b)(2), Information Exchange and Confidentiality, and shall notify BPA of any changes to Points of Delivery, Points of Metering, Interchange Points and related information for which it is responsible. BPA shall list «Customer Name»'s PODs and meters in Exhibit D, Metering. BPA may unilaterally revise the Metering exhibit to correctly reflect the Points of Delivery, Points of Metering, Interchange Points and related information, as required to operate under and to administer this Agreement.

10. BILLING AND PAYMENT *(10/17/07 Version)*

(a) **Billing**
BPA shall bill «Customer Name» monthly for any products and services provided during the preceding month(s). BPA may send «Customer Name» an estimated bill followed by a final bill. BPA shall send all bills on the bill's issue date. If electronic transmittal of the entire bill is not practical, BPA shall transmit a summary electronically, and send the entire bill by United States mail.

(b) **Payment***(03/26/08 Version)*
«Customer Name» shall pay all bills electronically in accordance with instructions on the bill. Payment of all bills, whether estimated or final, must be received by the 20th day after the issue date of the bill (Due Date). If the 20th day is a Saturday, Sunday, or federal holiday, the Due Date is the next business day. If «Customer Name» has made payment on an estimated bill then:

(1) if the amount of the final bill exceeds the amount of the estimated bill, «Customer Name» shall pay BPA the difference between the estimated bill and final bill by the final bill's Due Date; and

(2) if the amount of the final bill is less than the amount of the estimated bill, BPA shall pay «Customer Name» the difference between the estimated bill and final bill by the 20th day after the final bill's issue date. If the 20th day is a Saturday, Sunday, or federal holiday, BPA shall pay the difference by the next business day.

(c) **Late Payments***(03/26/08 Version)*
After the Due Date, a late payment charge equal to the higher of:

(1) the Prime Rate (as reported in the Wall Street Journal or successor publication in the first issue published during the month in which payment was due) plus 4 percent, divided by 365; or

(2) the Prime Rate times 1.5, divided by 365;

shall be applied each day to any unpaid balance.

(d) **Termination***(03/26/08 Version)*
If «Customer Name» is more than 45 days late from the Due Date in paying its bills under this Agreement, BPA may require additional forms of payment assurance acceptable to BPA. If «Customer Name» does not provide such payment assurance and BPA determines in its sole discretion that «Customer Name» is unable to make the payments owed, BPA may terminate this Agreement.

(e) **Disputed Bills***(03/26/08 Version)*
If «Customer Name» disputes any portion of a bill, «Customer Name» shall provide notice to BPA with a copy of the bill noting the disputed amounts. If any portion of the bill is in dispute, «Customer Name» shall pay the entire bill by the Due Date. Unpaid bills (including both disputed and undisputed amounts) are subject to the late payment charges provided above. If the Parties agree, or if it is determined after dispute resolution, that «Customer Name» is entitled to a refund of any portion of the disputed amount, BPA shall make such refund with simple interest computed from the date of receipt of the disputed payment to the date the refund is made. The daily interest rate shall equal the Prime Rate (as reported in the Wall Street Journal or successor publication in the first issue published during the month in which payment was due) divided by 365.

11. INFORMATION EXCHANGE AND CONFIDENTIALITY

Reviewer's Note: Exhibits & other sections of this Agreement may also have data requirements.

(a) **General Requirement** *(02/28/08 Version)*
Each Party shall provide the other Party with any information that is necessary to administer this Agreement, and to forecast «Customer Name»'s Total Retail Load, forecast BPA system load, comply with NERC reliability standards, prepare power bills, resolve billing disputes, administer transfer service, and to otherwise implement this Agreement. This obligation

includes transmission and power scheduling information and load and resource metering information (such as one-line diagrams, metering diagrams, loss factors, etc.).

(b) **Reports, Measured Data, and Load Data** *(03/02/08 Version, Revised for NR Block. Information needed to establish HWM deleted.)*

(1) **Reports**

(A) Within 30 days after final approval by the «Customer Name»'s governing body, «Customer Name» shall provide BPA with its annual financial report and statements.

(B) Within 30 days after their submittal to the Energy Information Administration, «Customer Name» shall provide BPA with a copy of its Annual Form EIA-861 Reports. If «Customer Name» is not otherwise required to submit such reports to the EIA, then this requirement does not apply.

(2) **Meter Data**

(A) In accordance with section 9(e), Metering, and Exhibit D, Metering, «Customer Name» shall notify BPA of any changes to Points of Delivery, Points of Metering, Interchange Points and related information for which it is responsible. «Customer Name» shall ensure BPA has access to all data from load and resource meters that BPA determines is necessary to forecast, plan, schedule, and bill. Access to this data shall be on a schedule determined by BPA. Meter data shall be in hourly increments for all meters that record hourly data. Meter data includes, but is not limited to: «Customer Name»'s actual amounts of energy used or expended for loads and resources, and the physical attributes of «Customer Name»'s meters.

(B) «Customer Name» consents to allow Power Services to receive the following information from Transmission Services or BPA's metering function: i) «Customer Name»'s meter data, as specified above in section 14(b)(2)(A), section 12(e), Metering, and Exhibit E, Metering, and ii) notification of outages or load shifts.

(C) At least 15 calendar days in advance, «Customer Name» shall e-mail BPA at: (i) mdm@bpa.gov and (ii) the contact shown in section 17, Notices and Contact Information, when the following events are planned to occur on «Customer Name»'s system: (i) installation of a new meter, (ii) changes or updates to an existing meter not owned by BPA, (iii) any planned line or meter outages, and (iv) any planned load shifts.

(D) If an unplanned load shift or outage occurs, «Customer Name» shall e-mail BPA at: (i) mdm@bpa.gov, and (ii) the contact shown in section 17, Notices and Contact Information, within 72 hours after the event.

Reviewer's Note: Except for the highlighted portion below, the language is identical to the language above in subsection (4) for the Load Following customers that were Block or Block/Slice customers during Subscription.

(3) **Hourly Total Retail Load Data**

Reviewer's Note: The data required below will be used by BPA for purposes of determining each customer's Net Requirement.

Unless BPA notifies «Customer Name» in writing that BPA has adequate hourly meter data to calculate «Customer Name»'s Total Retail Load, «Customer Name» shall provide the following hourly data electronically to BPA. «Customer Name» shall submit such data in a comma-separated-value (csv) format with the time/date stamp in one column and load amounts, with units of measurement specified, in another column.

(A) By December 31, 2009, «Customer Name» shall send to BPA «Customer Name»'s actual hourly Total Retail Load data for Fiscal Year 2002 through Fiscal Year 2009.

(B) By December 31, 2010, «Customer Name» shall send to BPA, «Customer Name»'s actual hourly Total Retail Load data for each for Point of Delivery for Fiscal Year 2010.

(C) By December 31, 2011, and by December 31 of each year thereafter, «Customer Name» shall send BPA «Customer Name»'s actual hourly Total Retail Load data for the immediately preceding Fiscal Year.

(4) **Total Retail Load Forecast** *(03/28/08 Version)*

Reviewer's Note: The data required below will be used by BPA for purposes of calculating Net Requirements and meeting WECC data reporting requirements.

By June 30, 2011, and by June 30 of each year thereafter, «Customer Name» shall provide BPA a forecast of «Customer Name»'s monthly energy and «Customer Name»'s system coincidental peak of «Customer Name»'s Total Retail Load for the upcoming 10 Fiscal Years. «Customer Name» shall send the forecast to BPA electronically, in a comma-separated-value (csv) format. «Customer Name» shall send the csv file with the following data elements in separate columns:

(A) four-digit calendar year,

(B) three-character month identifier,

(C) monthly energy forecast,

(D) unit measurement of monthly energy forecast,

(E) monthly «Customer Name»-system coincidental peak forecast, and

(F) unit measurement of monthly «Customer Name»-system coincidental peak forecast.

(c) **Resource Adequacy** *(02/28/08 Version)?*
The requirements of this section 11(c) are waived if «Customer Name» purchases all of its power for service to its Total Retail Load from BPA.

By November 30, 2010 and by November 30 each year after that, «Customer Name» shall provide to the Pacific Northwest Utilities Conference Committee (PNUCC), or its successor, forecasted loads and resources data to facilitate a region-wide assessment of loads and resources in a format, length of time, and level of detail specified in PNUCC's Northwest Regional Forecast Data Request.

After consultation with the Regional Resource Adequacy Forum, BPA may require «Customer Name» to submit any data to the Northwest Power and Conservation Council (Council) that BPA determines is necessary for the Council to perform regional resource adequacy assessments.

(d) **Confidentiality** *(01/17/08 Version)*
Before «Customer Name» provides information that is subject to a privilege of confidentiality or nondisclosure to BPA, «Customer Name» shall clearly mark such information as confidential. BPA shall notify «Customer Name» as soon as practicable of any request received under the Freedom of Information Act (FOIA), or under any other federal law or court or administrative order, for any confidential information. BPA shall only release such confidential information to comply with FOIA or if required by any other federal law or court or administrative order. BPA will limit the use and dissemination of confidential information within BPA to employees who need it for purposes of administering this Agreement.

12. NOTICES AND CONTACT INFORMATION *(03/30/08 Version)*
Any notice required under this Agreement shall be in writing and shall be delivered in person or with proof of receipt by a nationally recognized delivery service, by United States Certified Mail, or by another method agreed to by the Parties. Notices are effective when received. Either Party may change the name or address for delivery of notice by providing notice of such change or other mutually agreed method. The Parties shall deliver notices to the following person and address: *(Drafter's Note: Check BPA address and phone number prefix to ensure it is applicable.)*

If to «Customer Name»:

«Utility Name»
«Street Address»
«P.O. Box»
«City, State, Zip»
Attn: «Name»
«Title»
Phone: «###-###-####»
FAX: «###-###-####»
E-Mail: «E-Mail Address»

If to BPA:

Bonneville Power Administration
«Street Address»
«P.O. Box»
«City, State, Zip»
Attn: «AE Name - Routing»
Account Executive
Phone: «###-###-####»
FAX: «###-###-####»
E-Mail: « E-Mail Address »

13. UNCONTROLLABLE FORCES *(04/02/08 Version, Revised for NR Block. Section number reference in last sentence differs)*

(a) The Parties shall not be in breach of their respective obligations to the extent the failure to fulfill any obligation is due to an Uncontrollable Force. "Uncontrollable Force" means an event beyond the reasonable control of, and without the fault or negligence of, the Party claiming the Uncontrollable Force, that prevents that Party from performing its contractual obligations under this Agreement and which, by exercise of that Party's reasonable diligence and foresight, such Party was unable to avoid. Uncontrollable Forces include, but are not limited to:

(1) any unplanned curtailment or interruption of firm transmission service used to deliver Firm Requirements Power sold under this Agreement to «Customer Name»;

(2) any planned curtailment or interruption of long-term firm transmission service used to deliver Firm Requirements Power sold under this Agreement to «Customer Name» if such curtailment or interruption occurs on BPA's or a Third Party's Transmission System;

(3) any failure of «Customer Name»'s distribution or transmission facilities that prevents «Customer Name» from delivering power to end-users;

(4) strikes or work stoppage;

(5) floods, earthquakes, or other natural disasters; and

(6) orders or injunctions issued by a court or regulatory body having competent subject matter jurisdiction which the Party claiming the Uncontrollable Force, after diligent efforts, was unable to have stayed, suspended, or set aside pending review by a court of competent subject matter jurisdiction.

(b) Neither the unavailability of funds or financing, nor conditions of national or local economies or markets shall be considered an Uncontrollable Force. The economic hardship of either Party shall not constitute an Uncontrollable Force. Nothing contained in this provision shall be construed to require either Party to settle any strike or labor dispute in which it may be involved.

(c) If an Uncontrollable Force prevents a Party from performing any of its obligations under this Agreement, such Party shall:

(1) immediately notify the other Party of such Uncontrollable Force by any means practicable and confirm such notice in writing as soon as reasonably practicable;

(2) use its best efforts to mitigate the effects of such Uncontrollable Force, remedy its inability to perform, and resume full performance of its obligation hereunder as soon as reasonably practicable;

(3) keep the other Party apprised of such efforts on an ongoing basis; and

(4) provide written notice of the resumption of performance.

Written notices sent under this section must comply with section 12, Notices and Contact Information.

14. GOVERNING LAW AND DISPUTE RESOLUTION *(04/07/08 version Revised 04/07/2008 for NR Block. Section number references differ.)*

This Agreement shall be interpreted consistent with and governed by federal law. The Parties shall identify issue(s) in dispute and make a good faith effort to negotiate a resolution of disputes before either Party may initiate litigation or arbitration. Such good faith effort shall include discussions or negotiations between the Parties' executives or managers. During a contract dispute or contract issue between the Parties arising out of this Agreement, the Parties shall continue performance under this Agreement pending resolution of the dispute, unless to do so would be impossible or impracticable. The Parties reserve their rights to seek judicial resolution of any dispute arising under this Agreement.

(a) **Judicial Resolution**

Final actions subject to section 9(e) of the Northwest Power Act are not subject to arbitration under this Agreement and shall remain within the exclusive jurisdiction of the United States Ninth Circuit Court of Appeals. Such final actions include, but are not limited to, the establishment and implementation of rates and rate methodologies. Any dispute regarding any rights of the Parties under any BPA policy, including the implementation of such policy, shall not be subject to arbitration under this Agreement. For purposes of this section 14, BPA policy means any written document adopted by BPA as a final action in a decision record or record of decision that establishes a policy of general application, or makes a determination under an applicable statute. If either Party asserts that a dispute is excluded from arbitration under this section 14, then both Parties shall apply to the federal court having jurisdiction for an order determining whether such dispute is subject to arbitration under this section 14.

(b) **Arbitration**
Any contract dispute or contract issue between the Parties arising out of this Agreement, which is not excluded by section 14(a) above, shall be subject to arbitration. During arbitration, the Parties shall continue performance under this Agreement pending resolution of the dispute, unless to do so would be impossible or impracticable.

To resolve disputes that Parties agree are strictly issues of fact, binding arbitration may be used consistent with BPA's Binding Arbitration Policy or its successor. Before initiating binding arbitration, the Parties shall draft and sign an agreement to engage in binding arbitration, which shall set forth the precise issue in dispute, the amount in controversy, and the maximum monetary award allowed, pursuant to BPA's Binding Arbitration Policy or its successor.

(c) **Arbitration Procedure**
Any arbitration shall take place in Portland, Oregon, unless the Parties agree otherwise. The Parties agree that a fundamental purpose for arbitration is the expedient resolution of disputes; therefore, the Parties shall make best efforts to resolve an arbitrable dispute within one year of initiating arbitration. The rules for arbitration shall be agreed to by the Parties.

(d) **Arbitration Remedies**
The payment of monies shall be the exclusive remedy available in any arbitration proceeding. Under no circumstances shall specific performance be an available remedy against BPA.

(e) **Finality**

(1) In binding arbitration, the arbitration award shall be final and binding on both Parties, except that either Party may seek judicial review based upon any of the grounds referred to in the Federal Arbitration Act, 9 U.S.C. §1-16 (1988). Judgment upon the award rendered by the arbitrators may be entered by any court having jurisdiction thereof.

(2) In non-binding arbitration, the arbitration award is not binding on the Parties. Subsequent to non-binding arbitration, Parties may seek judicial resolution of the dispute.

(f) **Arbitration Costs**
Each Party shall be responsible for its own costs of arbitration, including legal fees. The arbitrator(s) may apportion all other costs of arbitration between the Parties in such manner as the arbitrator(s) deem reasonable taking into account the circumstances of the case, the conduct of the Parties during the proceeding, and the result of the arbitration.

15. STATUTORY PROVISIONS

(a) **Retail Rate Schedules** *(09/04/07 Version)*
«Customer Name» shall provide BPA with its retail rate schedules, as required by section 5(a) of the Bonneville Project Act, P.L. 75-329, within 30 days of each of «Customer Name»'s retail rate schedule effective dates.

(b) **Insufficiency and Allocations** *(04/04/08 Version, Revised for NR Block 4/9/08. Reference to Exhibit C removed in last sentence. In Publics' Block Exhibit C involves Purchase Obligations)*
If BPA determines, consistent with section 5(b) of the Northwest Power Act and other applicable statutes, that it will not have sufficient resources on a planning basis to serve its loads after taking all actions required by applicable laws then BPA shall give «Customer Name» a written notice that BPA may restrict service to «Customer Name». Such notice shall be consistent with BPA's insufficiency and allocations methodology, published in the Federal Register on March 20, 1996, and shall state the effective date of the restriction, the amount of «Customer Name»'s load to be restricted and the expected duration of the restriction. BPA shall not change that methodology without the written agreement of all public body, cooperative, federal agency and investor-owned utility customers in the Region purchasing federal power from BPA under section 5(b) of the Northwest Power Act. Such restriction shall take effect no sooner than five years after BPA provides notice to «Customer Name». If BPA imposes a restriction under this provision then the amount of Firm Requirements Power that «Customer Name» is obligated to purchase pursuant to section 3 of this Agreement shall be reduced to the amounts available under such allocation methodology for restricted service.

(c) **New Large Single Loads**

(1) **Determination of an NLSL** *(02/28/08 Version)*
In accordance with BPA's NLSL Policy, BPA may determine that a load is an NLSL as follows:

(A) BPA shall determine an increase in production load to be an NLSL if the energy consumption of the end-use consumer's load associated with a single new facility, an existing facility, or expansion of an existing facility during the immediately past consecutive twelve months equals or exceeds by 10 aMW (87,600,000 kilowatt hours) the greater of:

(i) the end-use consumer's energy consumption for such facility for the consecutive twelve months one year earlier, or

(ii) the amount of the contracted for, or committed to (CF/CT) load of the end-use consumer as of September 1, 1979; or

(B) The Parties may agree that the installed production equipment at a facility will exceed 10 aMW consumption over any twelve consecutive months and such agreement shall constitute a binding NLSL determination.

(2) **Determination of a Facility** *(09/04/07 Version)*
BPA shall make a written determination as to what constitutes a single facility, for the purpose of identifying an NLSL, based on the following criteria:

(A) whether the load is operated by a single end-use consumer;

(B) whether the load is in a single location;

(C) whether the load serves a manufacturing process which produces a single product or type of product;

(D) whether separable portions of the load are interdependent;

(E) whether the load is contracted for, served or billed as a single load under «Customer Name»'s customary billing and service policy;

(F) consideration of the facts from previous similar situations; and

(G) any other factors the Parties determine to be relevant.

(3) **Administrative Obligations and Rights** *(4/06/08 Version, Revised for NR Block 4/9/08. Section numbers differ.)*
Drafter's Note: If customer has a new or existing NLSL or CF/CT, include details of the NLSL or CF/CT and the manner of service in Exhibit D, Additional Products and Special Provisions.

(A) «Customer Name»'s NLSLs and CF/CT loads are listed in Exhibit B, Additional Products and Special Provisions.

(B) «Customer Name» shall provide reasonable notice to BPA of any expected increase in a single load that may qualify as an NLSL. The Parties shall list any such potential NLSLs in Exhibit B, Additional Products and Special Provisions. If BPA determines that any load associated with a single facility that is capable of growing 10 aMW or more in a consecutive twelve-month period, then such load shall be subject to monitoring by BPA.

(C) When BPA makes a request, «Customer Name» shall provide physical access to its substations and other service locations where BPA needs to perform inspections or gather information for purposes of implementing section 3(13) of the Northwest Power Act, including but not limited to making a final NLSL, facility, or CF/CT determination. «Customer Name» shall also require the end-use consumer to provide BPA physical access to inspect any facility for these purposes.

(D) Unless the Parties agree pursuant to section 15(c)(1)(B) above, BPA shall unilaterally determine whether a new load or an increase in existing load at a facility is an NLSL. If BPA determines that the load is an NLSL, BPA shall notify «Customer Name» and the Parties shall add the NLSL to Exhibit B, Additional Products and Special Provisions.

(4) **Metering an NLSL** *(4/06/08 Version) (03/30/08 Version)*
For any loads that are monitored by BPA for an NLSL determination, and at any facility that is determined by BPA to be an NLSL, «Customer Name» agrees to either consent to BPA installing BPA owned meters or «Customer Name» shall install meters meeting the exact specification BPA provides to «Customer Name». «Customer Name» and BPA shall enter into a separate agreement for the location, ownership, cost responsibility, access, maintenance, testing, replacement and liability of the Parties with respect to such meters. «Customer Name» shall arrange for metering locations that allow accurate measurement of the facility's load. «Customer Name» shall arrange for BPA to have physical access to such meters and «Customer Name» shall ensure BPA has access to all NLSL meter data that BPA determines is necessary to forecast, plan, schedule, and bill for power.

(5) **Undetermined NLSLs** *(04/06/08 Version, Revised for NR Block 4/9/08. Paragraph omitted that discusses back billing option for potential NLSLs because IOUs are not eligible for PF.)*
If BPA concludes in its sole judgment that «Customer Name» has not fulfilled its obligations under sections 15(c)(3) and 15(c)(4), BPA may determine any load subject to NLSL monitoring to be an NLSL. Such NLSL determination shall be final unless «Customer Name» proves to BPA's satisfaction that the applicable load did not exceed 10 aMW in any twelve month monitoring period.

(6) **Service Elections for an NLSL** *(02/28/08 Version)*
«Customer Name» shall serve all NLSLs with non-federal firm resources that are not already dedicated and declared in Exhibit A, Net Requirements and Exhibit B, Additional Products and Special Provisions, to serve «Customer Name»'s Total Retail Load in the region. «Customer Name» agrees to provide such dedicated firm resources on a continuous basis as identified in Exhibit A, Net Requirements. Under no circumstances shall BPA be required to acquire firm power for service to such NLSLs.

(7) **Renewable Resource/Cogeneration Exception** *(4/6/08 Version)* An end-use consumer served by «Customer Name», with a facility whose load is a NLSL, may reduce its NLSL to less than 10 average megawatts by applying an on-site renewable resource or on-site cogeneration behind the customer's meter to its facility load. «Customer Name» shall ensure that such resource is continuously applied to serve the NLSL, consistent with BPA's "Renewables and On-Site Cogeneration Option under the NLSL Policy" portion of its Policy for Power Supply Role for Fiscal Years 2007-2011, adopted February 4, 2005, and the NLSL policy included in BPA's Long Term Regional Dialogue Final Policy, July 2007, as amended or replaced. If the NLSL end-use consumer meets the qualification for the exception, the Parties shall amend Exhibit D, Additional Products and Special Provisions to add the on-site renewable resource or cogeneration facility and the requirements for such service.

(d) **Priority of Pacific Northwest Customers** *(09/04/07 Version)*
The provisions of sections 9(c) and (d) of the Northwest Power Act and the provisions of P.L. 88-552 as amended by the Northwest Power Act are incorporated into this Agreement by reference. «Customer Name», together with other customers in the Region, shall have priority to BPA power consistent with such provisions.

(e) **Prohibition on Resale** *(09/04/07 Version)*
«Customer Name» shall not resell Firm Requirements Power except to serve «Customer Name»'s Total Retail Load or as otherwise permitted by federal law.

(f) **Use of Regional Resources** *(02/28/08 Version)*

(1) Within 60 days prior to the start of each Fiscal Year, «Customer Name» shall provide notice to BPA of any firm power from a Generating Resource, or a Contract Resource during its term, that has been used to serve firm consumer load in the Region and that «Customer Name» plans to export for sale outside the Region in the next Fiscal Year. BPA may request additional information on «Customer Name»'s sales and dispositions of non-federal resources if BPA has information that «Customer Name» may have made such an export and not notified BPA. BPA may request and «Customer Name» shall provide within 30 days of such request, information on the planned use of any or all of «Customer Name» Generating and Contract Resources.

(2) «Customer Name» shall be responsible for monitoring any firm power from Generating Resources and Contract Resources it sells in the Region to ensure such firm power is planned to be used to serve firm consumer load in the Region.

(3) If «Customer Name» fails to report to BPA in accordance with section 15(f)(1), above, any of its planned exports for sale outside the Region of firm power from a Generating Resource or a Contract Resource that has been used to serve firm consumer load in the Region, and BPA makes a finding that an export which was not reported was made, BPA shall decrement the amount of its Firm Requirements Power sold under this Agreement by the amount of the export that was not reported, for the duration of the export. When applicable such decrements shall be identified in section 7(b) of Exhibit A, Net Requirements.

(4) For purposes of this section, an export for sale outside the Region means a contract for the sale or disposition of firm power from a Generating Resource, or a Contract Resource during its term, that has been used to serve firm consumer load in the Region in a manner that such output is no longer used or not planned to be used solely to serve firm consumer load in the Region. Delivery of firm power outside the Region under a seasonal exchange agreement that is made consistent with BPA's section 9(c) policy will not be considered an export. Firm power from a Generating Resource or a Contract Resource used to serve firm consumer load in the Region means the firm generating or load carrying capability of a Generating Resource or a Contract Resource as established under Pacific Northwest Coordination Agreement resource planning criteria, or other resource planning criteria generally used for such purposes within the Region.

(g) **BPA Appropriations Refinancing** *(09/04/07 Version)*
The Parties agree that the Bonneville Power Administration Refinancing section of the Omnibus Consolidated Recisions and Appropriations Act of 1996 (The BPA Refinancing Act), P.L. 104-134, 110 Stat. 1321, 350, as stated in the United States Code on the date this Agreement is signed by the Parties, is incorporated by reference and is a material term of this Agreement.

16. STANDARD PROVISIONS

(a) **Amendments** *(09/04/07 Version)*
Except where this Agreement explicitly allows for one Party to unilaterally amend a provision or exhibit, no amendment of this Agreement shall be of any force or effect unless set forth in a written instrument signed by authorized representatives of each Party.

(b) **Entire Agreement and Order of Precedence** *(09/26/07 Version)*
This Agreement, including documents expressly incorporated by reference, constitutes the entire agreement between the Parties. It supersedes all previous communications, representations, or contracts, either written or oral, which purport to describe or embody the subject matter of this Agreement. The body of this Agreement shall prevail over the exhibits to this Agreement in the event of a conflict.

(c) **Assignment** *(09/04/07 Version)*
This Agreement is binding on any successors and assigns of the Parties. Neither Party may otherwise transfer or assign this Agreement, in whole or in part, without the other Party's written consent. Such consent shall not be unreasonably withheld. BPA's refusal to consent to assignment shall not be considered unreasonable if the sale of power by BPA to the assignee would violate any applicable statute. «Customer Name» may not transfer or assign this Agreement to any of its retail consumers.

(d) **No Third-Party Beneficiaries** *(10/01/07 Version)*
This Agreement is made and entered into for the sole benefit of the Parties, and the Parties intend that no other person or entity shall be a direct or indirect beneficiary of this Agreement.

(e) **Waivers** *(10/01/07 Version)*
No waiver of any provision or breach of this Agreement shall be effective unless such waiver is in writing and signed by the waiving Party, and any such waiver shall not be deemed a waiver of any other provision of this Agreement or any other breach of this Agreement.

(f) **BPA Policies** *(09/04/07 Version)*
Any reference in this Agreement to BPA policies, including any revisions, does not constitute agreement of «Customer Name» to such policy by execution of this Agreement, nor shall it be construed to be a waiver of the right of «Customer Name» to seek judicial review of any such policy.

(g) **Rate Covenant and Payment Assurance** *(03/28/08 Version)*
«Customer Name» agrees that it shall establish, maintain and collect rates or charges for power and energy and other services, facilities and commodities sold, furnished or supplied by it through any of its electric utility properties. BPA may require additional forms of payment assurance if: (i) BPA determines that such rates and charges may not be adequate to provide revenues sufficient to enable «Customer Name» to make the payments required under this Agreement, or (ii) BPA identifies in a letter to «Customer Name» that BPA has other reasonable grounds to conclude that «Customer Name» may not be able to make the payments required under this Agreement. If «Customer Name» does not provide payment assurance satisfactory to BPA, BPA may terminate this Agreement.

17. TERMINATION *(04/06/08 Version, Revised for NR Block 4/9/08. Section revised to exclude references to Slice, tiered rates.)*

(a) **BPA's Right to Terminate**
BPA may terminate this Agreement if:

(1) «Customer Name» fails to make payment as required by section 13(d), Billing and Payment, or

(2) «Customer Name» fails to provide payment assurance satisfactory to BPA as required by section 22(g), Rate Covenant and Payment Assurance.

(b) **Contract Invalidity**
«Customer Name» may terminate this Agreement not later than sixty (60) days after any material term, provision or condition of this Agreement, or the performance of any such material term, provision or condition is held by a final order of a Federal court having jurisdiction to be invalid or unenforceable, or is enjoined.

18. SIGNATURES *(10/01/07 Version)*
The signatories represent that they are authorized to enter into this Agreement on behalf of the Party for which they sign.

«FULL NAME OF CUSTOMER»		UNITED STATES OF AMERICA Department of Energy Bonneville Power Administration	
By	____________________	By	____________________
Name	____________________ *(Print/Type)*	Name	____________________ *(Print/Type)*
Title	____________________	Title	____________________
Date	____________________	Date	____________________

(PS«X/LOC»- «File Name with Path».DOC) «mm/dd/yy» *{Drafter's Note: Insert date of finalized contract here*

Exhibit A
NET REQUIREMENTS *(04/05/08 Version)*

1. ESTABLISHING NET REQUIREMENTS

«Customer Name»'s Net Requirement equals its Total Retail Load minus «Customer Name»'s non-federal resource amounts, including consumer-owned resource amounts listed in sections 5 and 6 of this exhibit. «Customer Name» shall not add resource amounts to reduce its purchase obligations from BPA under section 3 of the body of this Agreement except to meet load obligations in section 4 of this exhibit.

BPA shall annually calculate a forecast of «Customer Name»'s Net Requirement for the upcoming Fiscal Year as follows:

(a) **Forecast of Total Retail Load**
By September 30, 2011, and by each September 30 thereafter, BPA shall fill in the table below with «Customer Name»'s Total Retail Load forecast (submitted pursuant to section 14(b)(5) of the body of this Agreement) for the upcoming Fiscal Year. BPA shall notify «Customer Name» before the start of the Fiscal Year if BPA determines «Customer Name»'s submitted forecast is reasonable or not reasonable. If BPA determines «Customer Name»'s submitted forecast is not reasonable, BPA shall fill in the table below with a forecast BPA determines to be reasonable.

Table 1: Annual Forecast of Total Retail Load – Energy (aMW)									
Fiscal Year	2012	2013	2014	2015	2016	2017	2018	2019	2020
Annual aMW									
Fiscal Year	2021	2022	2023	2024	2025	2026	2027	2028	
Annual aMW									
Note: Fill in the table above with annual average megawatts rounded to three decimal places.									

(b) **Forecast of Net Requirements**
By September 30, 2011, and by each September 30 thereafter, BPA shall calculate, and fill in the table below with, «Customer Name»'s Net Requirement forecast for the upcoming Fiscal Year. «Customer Name»'s Net Requirement forecast equals «Customer Name»'s Total Retail Load forecast, shown in section 1(a) above, minus «Customer Name»'s total non-federal resource amounts dedicated to its Total Retail Load, shown in section 7 below.

Table 2: Annual Forecast of Net Requirements – Energy (aMW)									
Fiscal Year	2012	2013	2014	2015	2016	2017	2018	2019	2020
Annual aMW									
Fiscal Year	2021	2022	2023	2024	2025	2026	2027	2028	
Annual aMW									

Note: Fill in the table above with annual average megawatts rounded to three decimal places.

2. REVISIONS

BPA shall make adjustments to this exhibit to reflect (i) BPA's determinations under this Agreement and BPA's Policy on Determining Net Requirements of Pacific Northwest Utility Customers Under Sections 5(b)(1) and 9(c) of the Northwest Power Act issued May 23, 2000, as clarified March 21, 2003 (5(b)/9(c) Policy), and (ii) «Customer Name»'s elections regarding the application and use of all resources listed by «Customer Name» to serve its Total Retail Load, as provided under this Agreement.

3. RESOURCES DEDICATED TO TOTAL RETAIL LOAD

The non-federal resources described below are dedicated to serving «Customer Name»'s firm load pursuant to section 5(b) of the Northwest Power Act. Upon termination or expiration of this Agreement, «Customer Name» may discontinue serving its Total Retail Load with any Unspecified Resource Amounts.

(a) **Specified Resources**

«Customer Name» shall apply the output from all Specified Resources listed below in section 5 to serve its Total Retail Load. BPA shall use the amounts listed in section 5 to determine «Customer Name»'s Net Requirement under this Agreement; the amounts listed are not intended to interfere with «Customer Name»'s decisions on how to operate its Specified Resources.

(b) **Unspecified Resource Amounts**

In addition to the resource amounts listed in section 5 below, «Customer Name» shall serve its Total Retail Load with Unspecified Resource Amounts. By September 30, 2011, and by each September 30 thereafter, BPA shall calculate, and fill in the table below in section 6(a) with, «Customer Name»'s Unspecified Resource Amounts for the upcoming Fiscal Year.

4. CHANGES TO RESOURCE AMOUNTS

(a) **Resource Additions for a BPA Insufficiency Notice**

If BPA provides «Customer Name» a notice of insufficiency in accordance with section 15(b), Insufficiency and Allocations, of the body of this Agreement, «Customer Name» shall add Specified Resources or Unspecified Resource Amounts to sections 5 or 6 below to replace amounts of Firm Requirements Power BPA will not be providing due to insufficiency.

(b) **Decrements for 9(c) Export**

If BPA determines (in accordance with section 15(f), Use of Regional Resources, of the body of this Agreement) that an export of a Specified Resource listed in section 5 below requires a reduction in the amount of Firm Requirements Power BPA sells «Customer Name», BPA shall add Unspecified Resource Amounts to section 6(b) below. BPA shall notify «Customer Name» of the amount and duration of the reduction in «Customer Name»'s Firm Requirements Power purchases from BPA.

(c) **Permanent Discontinuance of Resources**
The Specified Resources listed below in section 5 may be removed permanently by «Customer Name» consistent with BPA's 5(b)/9(c) Policy on statutory discontinuance for permanent removal. If BPA makes a determination that «Customer Name»'s resource has met BPA's standards for a permanent removal, BPA shall revise this exhibit to show the resource changes. «Customer Name»'s additional power purchases under this Agreement, as a result of such a resource removal, may be subject to additional rates or charges as established in the GRSPs.

(d) **Changes to Consumer-Owned Resources**
«Customer Name» shall not remove any consumer-owned resources dedicated to serve «Customer Name»'s Total Retail Load during the term of this Agreement except as allowed in section 4(d) above.

(e) **Resource Additions for Annexed Loads**
To serve amounts of Annexed Loads that are added after this Agreement is executed, «Customer Name» shall add Specified Resources or Unspecified Resource Amounts to section 5 or 6 below, including any annexed Specified Resources. «Customer Name»'s additional power purchases under this Agreement, as a result of such Annexed Loads, may be subject to additional rates or charges as established in the GRSPs.

(f) **Resource Additions for NLSLs**
To serve NLSLs (established in Exhibit B, Additional Products and Special Provisions) that are added after this Agreement is executed, «Customer Name» may add Specified Resources or Unspecified Resource Amounts to sections 5 or 6 below.

5. SPECIFIED RESOURCES DEDICATED TO TOTAL RETAIL LOAD
«Customer Name» shall list below all Specified Resources that are greater than 200 kilowatts of nameplate capability. For each Specified Resource listed below «Customer Name» shall list dedicated resource amounts for each month beginning with the later of (i) the date the resource was dedicated to load, or (ii) October 1, 2011, through to the earlier of (i) the date of resource removal or (ii) September 30, 2028. «Customer Name» shall provide BPA with all resource profile data BPA determines is necessary to implement this Agreement and any additional resource data BPA determines is necessary to verify the dedicated resource amounts listed below.
Drafter's Note: List each Specified Resource, in the applicable subsection, using the format shown below in section 5(a)(1).

(a) **Generating Resources**
All of «Customer Name»'s Generating Resources dedicated to serve its Total Retail Load shall be listed below.

(1) **«Resource Name»**

Drafter's Note: If «Customer Name» has Generating Resources fill in the tables below (one set of tables for each Generating Resource). If «Customer Name» does not have any Generating Resources, keep this provision and the tables below (leaving the tables blank) and write "No Generating Resources at this time" above as the title of section 5(a)(1).

(A) **Resource Profile**

Resource Name	Fuel Type	Date Resource Dedicated to Load	Date of Resource Removal	Percent Dedicated to Load	Nameplate Capability (MW)

Owned By		Statutory Status		Diurnal Flattening Service?		Dispatchable?		PNCA?		If PNCA, PNCA Updates?	
«Customer Name»	Consumer	5b1A	5b1B	Yes	No	Yes	No	Yes	No	Yes	No
Note: Fill in the table above with "X"s.											

(B) **Dedicated Resource Amounts**

Total Energy Amounts (MWh)													
Fiscal Year	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Annual aMW
2012													
2013													
2014													
2015													
2016													
2017													
2018													
2019													
2020													
2021													
2022													
2023													
2024													
2025													
2026													
2027													
2028													
Note: Fill in the table above with megawatt-hours rounded to whole megawatt-hours and with average megawatts rounded to three decimal places.													

Attachment 3
04/14/08 Revision—NR BLOCK Template

HLH Energy Amounts (MWh)													
Fiscal Year	**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Annual aMW**
2012													
2013													
2014													
2015													
2016													
2017													
2018													
2019													
2020													
2021													
2022													
2023													
2024													
2025													
2026													
2027													
2028													
Note: Fill in the table above with megawatt-hours rounded to whole megawatt-hours and with average megawatts rounded to three decimal places.													

LLH Energy Amounts (MWh)													
Fiscal Year	**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Annual aMW**
2012													
2013													
2014													
2015													
2016													
2017													
2018													
2019													
2020													
2021													
2022													
2023													
2024													
2025													
2026													
2027													
2028													
Note: Fill in the table above with megawatt-hours rounded to whole megawatt-hours and with average megawatts rounded to three decimal places.													

Peak Amounts (MW)

Attachment 3
04/14/08 Revision—NR BLOCK Template

Fiscal Year	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
2012												
2013												
2014												
2015												
2016												
2017												
2018												
2019												
2020												
2021												
2022												
2023												
2024												
2025												
2026												
2027												
2028												
Note: Fill in the table above with megawatts rounded to three decimal places.												

(C) **Special Provisions**
Drafter's Note: Include any special provisions here that are applicable to this resource. If none, retain this section and state "None".

(b) **Contract Resources**
All of «Customer Name»'s Contract Resources dedicated to serve its Total Retail Load shall be listed in tables below in the format shown in section 5(a)(1) above.
Drafter's Note: If «Customer Name» has Contract Resources insert tables here. If «Customer Name» does not have any Contract Resources, write "No Contract Resources at this time" here.

6. UNSPECIFIED RESOURCE AMOUNTS DEDICATED TO TOTAL RETAIL LOAD

(a) **Unspecified Resource Amounts**
«Customer Name»'s Unspecified Resource Amounts dedicated to serve its Total Retail Load shall be listed below.

Total Unspecified Resource Amounts (MWh)													
Fiscal Year	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Annual aMW
2012													
2013													
2014													
2015													

2016													
2017													
2018													
2019													
2020													
2021													
2022													
2023													
2024													
2025													
2026													
2027													
2028													
Note: Fill in the table above with megawatt-hours rounded to whole megawatt-hours and with average megawatts rounded to three decimal places.													

HLH Unspecified Resource Amounts (MWh)													
Fiscal Year	**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Annual aMW**
2012													
2013													
2014													
2015													
2016													
2017													
2018													
2019													
2020													
2021													
2022													
2023													
2024													
2025													
2026													
2027													
2028													
Note: Fill in the table above with megawatt-hours rounded to whole megawatt-hours and with average megawatts rounded to three decimal places.													

LLH Unspecified Resource Amounts (MWh)													
Fiscal Year	**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Annual aMW**
2012													
2013													
2014													
2015													
2016													
2017													

2018													
2019													
2020													
2021													
2022													
2023													
2024													
2025													
2026													
2027													
2028													
Note: Fill in the table above with megawatt-hours rounded to whole megawatt-hours and with average megawatts rounded to three decimal places.													

(b) **Unspecified Resource Amounts for 9(c) Export Decrements**
Pursuant to section 4(b) above, BPA shall insert a table below for any decrements due to export of resources in the shape, duration, and amount of the export.

7. TOTAL RESOURCE AMOUNTS DEDICATED TO TOTAL RETAIL LOAD
The following amounts equal the sum of all resource amounts dedicated to «Customer Name»'s Total Retail Load listed above in sections 5 and 6.

Total Energy Amounts (MWh)													
Fiscal Year	**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Annual aMW**
2012													
2013													
2014													
2015													
2016													
2017													
2018													
2019													
2020													
2021													
2022													
2023													
2024													
2025													
2026													
2027													
2028													
Note: Fill in the table above with megawatt-hours rounded to whole megawatt-hours and with average megawatts rounded to three decimal places.													

HLH Energy Amounts (MWh)

Attachment 3
04/14/08 Revision—NR BLOCK Template

Fiscal Year	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Annual aMW
2012													
2013													
2014													
2015													
2016													
2017													
2018													
2019													
2020													
2021													
2022													
2023													
2024													
2025													
2026													
2027													
2028													

Note: Fill in the table above with megawatt-hours rounded to whole megawatt-hours and with average megawatts rounded to three decimal places.

LLH Energy Amounts (MWh)

Fiscal Year	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Annual aMW
2012													
2013													
2014													
2015													
2016													
2017													
2018													
2019													
2020													
2021													
2022													
2023													
2024													
2025													
2026													
2027													
2028													

Note: Fill in the table above with megawatt-hours rounded to whole megawatt-hours and with average megawatts rounded to three decimal places.

Total Peak Amounts (MW)

Fiscal Year	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep

04/14/08 Revision—NR BLOCK Template

Total Peak Amounts (MW)												
Fiscal Year	**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**
2012												
2013												
2014												
2015												
2016												
2017												
2018												
2019												
2020												
2021												
2022												
2023												
2024												
2025												
2026												
2027												
2028												
Note: Fill in the table above with megawatts rounded to three decimal places.												

Reviewer's Note: BPA needs the following information for WECC reporting standards and for Canadian treaty obligations.

8. LIST OF RESOURCES NOT DEDICATED TO TOTAL RETAIL LOAD

«Customer Name» shall list below, in the format provided, (i) any non-federal resources «Customer Name» owns that are not dedicated to serve «Customer Name»'s Total Retail Load, and (ii) any consumer-owned resources in «Customer Name»'s service territory that are not dedicated to serve «Customer Name»'s Total Retail Load; that are greater than 200 kilowatts of nameplate capability. «Customer Name» shall provide BPA with all resource profile data BPA determines is necessary and any additional resource data BPA determines is necessary to verify the information listed below.

(a) **«Resource Name»**

Drafter's Note: If «Customer Name» does not have any resources not dedicated to its load, keep this provision and the tables below (leaving the tables blank) and write "No resources at this time" above as the title for section8(a).

(1) **Resource Profile**

Resource Name	Fuel Type	Owned by		Nameplate Capability (MW)
		«Customer Name»	Consumer	

(2) **Expected Resource Output**

Expected Output – Energy (aMW)									
Fiscal Year	2012	2013	2014	2015	2016	2017	2018	2019	2020
Annual aMW									
Fiscal Year	2021	2022	2023	2024	2025	2026	2027	2028	
Annual aMW									
Note: Fill in the table above with annual average megawatts rounded to three decimal places.									

Exhibit B
ADDITIONAL PRODUCTS AND SPECIAL PROVISIONS

Reviewer's Note: *Exhibit B may be revised to add additional sections. For this reason, the NLSL section is*

3. NEW LARGE SINGLE LOADS *(12/27/07 Version)*

[BEGIN Potential NLSL Options

*Option 1: Include the following if customer **DOES NOT** have a **POTENTIAL** NLSL.*

(a) **Potential NLSLs**
«Customer Name» has no potential NLSLs.

*Option 2: Include the following if customer has a **POTENTIAL** NLSL.*

(a) **Potential NLSLs**
«Customer Name» has identified the following potential NLSL(s):

End-use consumer name: «_______»
Facility location: «_______»
Potential load size and date anticipated: «_______»
Description of potential NLSL: «_______»

END Potential NLSL Options]

(b) **List of NLSLs and CF/CTs**

[BEGIN NLSL OPTIONS

*Option 1: Include the following if customer **has no** existing NLSLs.*

(1) **NLSLs**
«Customer Name» has no NLSLs.

*Option 2: Include the following if customer **has** an existing NLSL.*

(1) **NLSLs**
«Customer Name» has an NLSL and agrees to serve the NLSL with a firm resource that is not already dedicated to serve its other firm end-use consumer loads. See Exhibit A, Net Requirements.

End–use consumer name: «_______»
Facility location: «_______»
Date load determined as an NLSL: «_______»
Description of NLSL: «_______»
Manner of service: «_______»

[BEGIN Renewable/Cogen Exception Options

*Option 1: Include the following if customer **has no** onsite renewable or cogeneration facilities to apply to an NLSL:*

(2) **Renewable Resource/Cogeneration Exception**

«Customer Name»'s end-use consumer is not applying an on-site renewable resource or cogeneration facility to an NLSL.

*Option 2: Include the following if customer **has** an onsite renewable or cogeneration facility to apply to an NLSL.*

(2) **Renewable Resource/Cogeneration Exception**
Drafter's Note: Use Revision 5 to Exhibit D under Flathead's Subscription Contract 00PB-12172 as a template and coordinate with the NLSL expert and general counsel to add specific renewable or cogeneration resource information.

END Renewable/Cogen Exception Options]

[BEGIN CF/CT OPTIONS

*Option 1: Include the following if customer has **no** CF/CT loads.*

(3) **CF/CT Loads**
«Customer Name» has no loads that were contracted for, or committed to (CF/CT), as of September 1, 1979, as defined in section 3(13)(A) of the Northwest Power Act.

*Option 2: Include the following if customer **has** CF/CT loads.*

(3) **CF/CT Loads**
The Administrator has determined that the following loads were contracted for, or committed to be served (CF/CT), as of September 1, 1979, as defined in section 3(13)(A) of the Northwest Power Act, and are subject to the applicable cost based rate for the rest of «Customer Name»'s load:

End-use consumer's name: «_______»
Amount of firm energy (megawatts at 100 percent load factor) contracted for, or committed to, as of September 1, 1979: «_______»
Facility location and description: «_______»

END CF/CT OPTIONS]

4. REVISIONS *(09/04/07 Version)*
This exhibit shall be revised by mutual agreement of the Parties to reflect additional products «Customer Name» purchases during the term of this Agreement.

(PS«X/LOC»- «File Name with Path».DOC) «mm/dd/yy» *{Drafter's Note: Insert date of finalized contract here*

Exhibit C
SCHEDULING

1. SCHEDULING FEDERAL RESOURCES

«Customer Name» is responsible for creating Electronic Tags for all deliveries of federal power purchased under this Agreement. "Electronic Tags" or "e-Tags" means a document describing a physical interchange transaction and its associated participants and is the result of one or more requests, or its successor definition as established by NERC.

2. SCHEDULING NON-FEDERAL RESOURCES

«Customer Name» shall electrically copy Power Services on all preschedule and real-time e-Tags associated with the delivery of «Customer Name»'s non-federal resources, if any, as listed in Exhibit A, Net Requirements.

3. AFTER THE FACT

BPA and «Customer Name» agree to reconcile all transactions, schedules and accounts at the end of each month (as early as possible within the first 10 calendar days of the next month). BPA and «Customer Name» will verify all transactions per this Agreement, as to product or type of service, hourly amounts, daily and monthly totals, and related charges.

4. REVISIONS

BPA may unilaterally revise this exhibit: (i) to implement changes that BPA determines are necessary to allow it to meet its power and scheduling obligations under this Agreement or (ii) to comply with requirements of the WECC, NAESB, or NERC, or their successors or assigns.

Revisions are effective 45 days after BPA provides written notice of the revisions to «Customer Name» unless, in BPA's sole judgment, less notice is necessary to comply with an emergency change to the requirements of the WECC, NAESB, NERC, or their successors or assigns. In this case, BPA shall specify the effective date of such revisions.

Attachment 3
04/14/08 Revision—NR BLOCK Template
Exhibit D
METERING*(04/03/08 Version)*

Drafter's Note: Include all three tables, but state "N/A" if the table does not apply for the particular customer's circumstances. In general, only customers who operate their own balancing authorities will complete Table 3 (Seattle, Tacoma, Douglas PUD, Grant PUD and all IOU's)

Reviewer's Note: The accuracy of the data elements comprising the metering exhibit is critical to BPA and its contractual relationship with its customers. Accordingly, organizational data stewards have been identified for each data element, business processes have been designed and sources of record identified to support the data stewards who have responsibility for the quality of this data. The BPA Account Executives are responsible for the accuracy of the overall table.

Table 1: Load Meters

Point of Delivery #	Point of Delivery Name	Meter #	Meter Name	Direction (For Billing Purposes)	Metering Location[1/]	Balancing Authority Area[2/]	Manner of Service[1/]
N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

[1/] B = Bonneville Power Administration; E = Example Public Utility District; S = Sample Cooperative. *Footnote 1 should be edited to only have abbreviations needed*

[2/] BPAT = BPA Transmission Balancing Authority

*(Drafter's Note: The following notes and terms are guidelines for developing the Metering Exhibit. Do not include the following in the final exhibit if not applicable. **Note**: B = footnote can be used for both P and T contracts; P = footnote used only for P contracts, T= footnote used only for T contracts.)*

[#/] *B* - The revenue meters are owned by «Owner Name». *(Note: Revenue meters are assumed to be owned by BPA – if not use this footnote.)*

[#/] *B* - Demand measurements are provided by a totalizing recording demand meter.

[#/] *P* -Service to this Point of Delivery is taken pursuant to transfer service under a Transfer Agreement with «Utility Name».

[#/] *B* - «Customer Name» provides «#» kV step-down to «#» kV delivery service at «Owner Name»'s «Substation Name» Substation. *(Use only if customer is providing step-down service and it is not a BPA owned substation.)*

[#/] *B* - The period of service for meter «POM #» shall commence when the «substation or equipment» is energized for commercial operation. *(Use only when adding a new metering point that has not yet been energized.)*

[#/] *B* - The period of service for meter «POM #» shall commence at «####» hours on «Month dd, yyyy». *(Use only if known.)*

[#/] *B* - The period of service for meter «POM #» shall end at «####» hours on «Month dd, yyyy». *(Use only if known.)*

[#/] *P* -This Point of Delivery «POD #» is subject to a «#,###» kW demand limit.

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04/14/08 Revision—NR BLOCK Template

[#/] *P* -This Point of Delivery «POD #» is subject to Low Voltage Delivery charges pursuant to section «#» of the body of this Agreement.
[#] *T*- Point of Delivery «POD #» is subject to Delivery charges pursuant to section «#» of the body of this Agreement.
[#/] *B* –There shall be an adjustment for losses between the Point of Delivery and the Point of Metering for meter «POM #», and such adjustment shall be specified in correspondence transmitted between BPA and «Customer Name».
[#] *B* -The Point of Delivery is located at «####».

Table 2: Resource Meters

Point of Delivery #	Point of Receipt Name	Meter #	Meter Name	Direction (For Billing Purposes)	Metering Location	Balancing Authority Area[2/]	Manner of Service[1/]
N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
1	Make Believe (115 kV)	1005	Co-Gen In (115 kV)	+	Co-Gen Plant	BPAT	Directly Connected to S
1	Make Believe (115 kV)	1006	Co-Gen Out (115 kV)	-	Co-Gen Plant	BPAT	Directly Connected to S

[1/] B = Bonneville Power Administration; E = Example Public Utility District; S = Sample Cooperative. *Footnote 1 should be edited to only have abbreviations needed*
[2/] BPAT = BPA Transmission Balancing Authority

*(Drafter's Note: The following notes and terms are guidelines for developing the Metering Exhibit. Do not include the following in the final exhibit if not applicable. **Note**: B = footnote can be used for both P and T contracts; P = footnote used only for P contracts.)*
[#/] *B* - The revenue meters are owned by «Customer Name». *(Note: Revenue meters are assumed to be owned by BPA – if not use this footnote.)*
[#/] *B* - Demand measurements are provided by a totalizing recording demand meter.
[#/] *B* - «Customer Name» provides «#» kV step-down to «#» kV delivery service at «Customer Name»'s «Substation Name» Substation. *(Use only if customer is providing step-down service and it is not a BPA owned substation.)*
[#/] *B* - The period of service for meter «POM #» shall commence when the «substation or equipment» is energized for commercial operation. *(Use only when adding a new metering point that has not yet been energized.)*
[#/] *B* - The period of service for meter «POM #» shall commence at «####» hours on «Month dd, yyyy». *(Use only if known.)*
[#/] *B* - The period of service for meter «POM #» shall end at «####» hours on «Month dd, yyyy». *(Use only if known.)*
[#/] *B* –There shall be an adjustment for losses between the Point of Receipt and the Point of Metering for meter «POM #», and such adjustment shall be specified in correspondence transmitted between BPA and «Customer Name».
[#] *B* -The Point of Receipt is located at «####».

Standard Terms – Tables 1 and 2
Point of Delivery/Point of Receipt # *is the BPA assigned number associated with a customer's specific POD/POR. (Note: a number is used instead of the substation name because different internal BPA automated tracking systems all use different nomenclature. Use of a number is a more reliable method used for our automated systems coming on line)*
Meter # *is the BPA assigned number associated with a customer's specific Point of Metering*

Attachment 3
04/14/08 Revision—NR BLOCK Template

Meter Name *is the name of the Point of Metering*
Direction *means the direction that is used for billing purposes. A "+" means the metered amount is added and "-" means the metered amount is subtracted to determine the customers load.*
Metering Location *means the location on the system where the power is metered, not the actual location of the meter.*
Balancing Authority Area *means the collection of generation, transmission, and loads within the metered boundaries of a Balancing Authority. The Balancing Authority maintains load-resource balance within this area. The Balancing Authority is the responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area, and supports interconnection frequency in real time.*
Manner of Service: Transfer *means that part of the wheeling of power and energy to the Point of Delivery that is via an intervening transmission system owned by a utility other than BPA. Usually "B to T to C" or "B to T to B to C."*
Manner of Service: Direct *means BPA transmission provides for the wheeling of power and energy from the Point of Receipt to the Point of Delivery without the services of an intervening transmission system. Usually "B to C."*
Manner of Service: Directly Connected *means the generation is directly connected to the customer's system.*
Manner of Service: Wheeled *means the resource is not connected directly to the customer's system And the power and energy from that generation is brought to the customer's system over another utility's transmission system.*

Table 3: Interchange Meters (Not to be used for billing purposes)

Name of Interchange Point (owner)	Metering Location	Balancing Authority Areas
N/A	N/A	N/A
Kitsap Interchange (BPA)	physical description	BPA/Puget

Standard Terms – Table 3
Name of Interchange Point (owner) *means the name of the interchange meter and who owns it. Interchange point means the points where Balancing Authority Areas interconnect and at which the interchange of energy between Balancing Authority Areas is monitored and measured.*
Metering Location *means the location on the system where the power is metered, not the actual location of the meter.*
Balancing Authority Area *means the collection of generation, transmission, and loads within the metered boundaries of a Balancing Authority. The Balancing Authority maintains load-resource balance within this area. The Balancing Authority is the responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area, and supports interconnection frequency in real time.*

Revisions

BPA may unilaterally revise the Metering exhibit to correctly reflect the Points of Delivery, Points of Metering, Interchange Points and related information, as required to operate under and to administer this Agreement. Revisions are effective when BPA provides written notice of the revisions to «Customer Name».

*** Reviewer's Note: Each data element has an owner (data steward) within BPA. TSRM = Oasis Management, TPC = Customer Service Engineers, TOT = Technical Operations, KSM = Metering Services. The Power Account Executives are responsible for validating the Customer-to-Meter relationship and the accuracy of the overall table. TPC will inform the Power AEs and KS of meter data element changes and the exhibit will be updated accordingly.**

Attachment 3
04/14/08 Revision—NR BLOCK Template

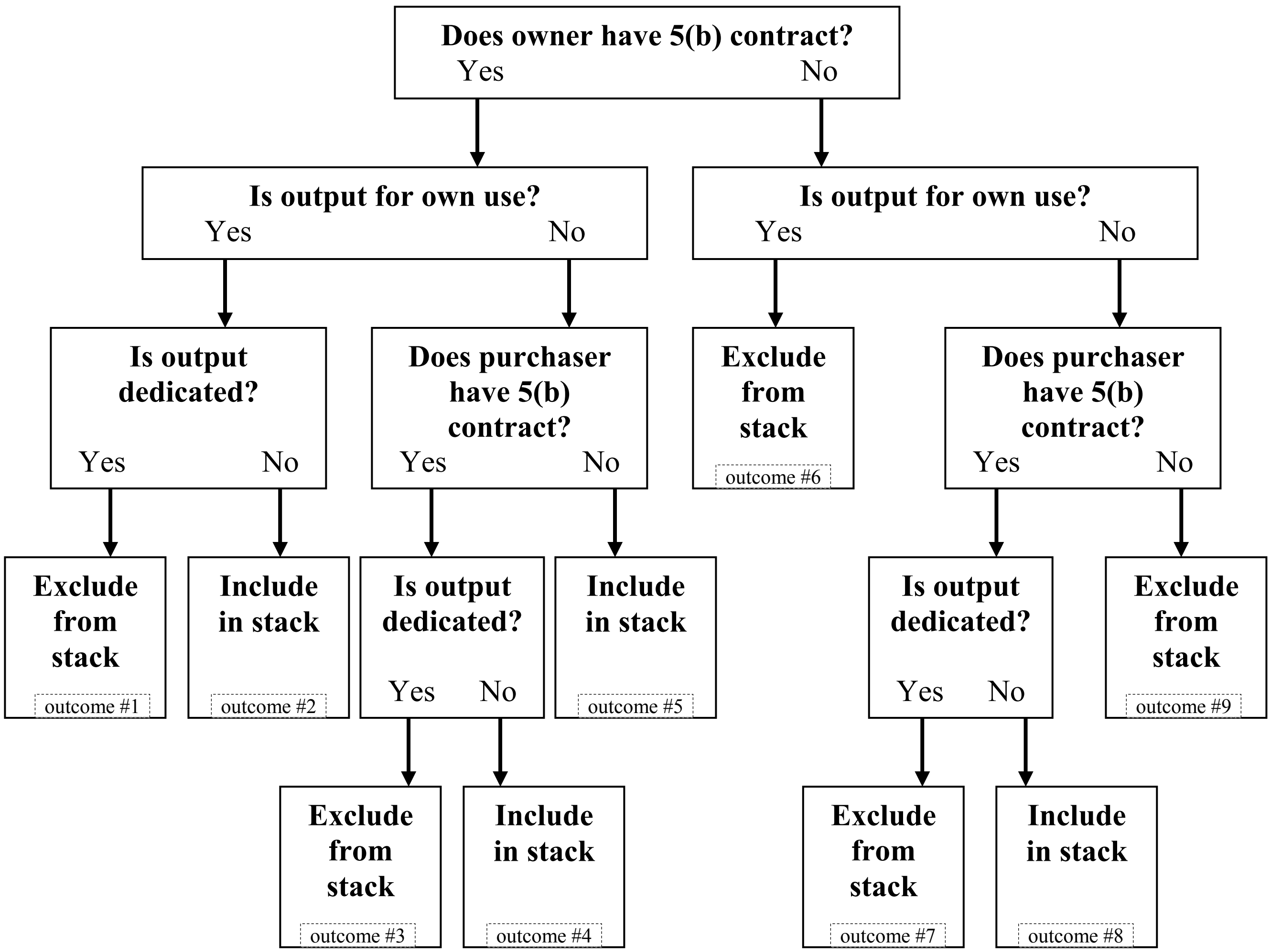
(Drafter's Note: The following notes and terms are guidelines for developing the Metering Exhibit. Do not include the following in the final exhibit. Footnote 1 should be edited to only have abbreviations needed.)

Standard Footnotes
The revenue meters are owned by ________. (Assume revenue meters are owned by BPA, otherwise use this footnote.)
Demand measurements are provided by a totalizing recording demand meter.
Subject to transfer pursuant to Transfer Agreement No. ____ between ________ and ________. (Only if customer is a Party to the transfer agreement.)
BPA provides Transfer Service for «Customer Name» over ________'s facilities.
________ provides ___ kV step-down to ___ kV delivery service at ________'s ________ Substation. (Use if utility besides BPA, the Transferor or customer provides the step-down transformation.)
The current and potential transformers are owned by ________. (Assume CT's and PT's are owned by the owner of the substation where the metering equipment is located. If not, use this footnote.)
The period of service for meter ________ shall commence when the facilities are energized for commercial operation.(Need to be more specific on what facilities, e.g. name the owner and the substation.)
The period of service for meter ________ shall end at ____ hours on _________.
This Point of Delivery is subject to a __ kW demand limit.
This Point of Delivery is subject to Low Voltage Delivery.

Standard Terms:
"Transfer" means that part of the wheeling of BPA power to the Point of Delivery which is via wheeling paid for by BPA. Usually "T to C" or "T to B to C."
"Direct" means a non-BPA transmission provider delivers the BPA power at a point of delivery which is between the transmission provider, and customer or an agent for customer. Usually "B to C."
"Directly Connected" or "Wheeled" means a description of how the resource is connected to customer's system.
"Metering Location" means the location on the system where the power is metered, not the actual location of the meter.

Attachment 4

7(b)(2)(D) Resource Decision Tree



ATTACHMENT 5
Mid-Columbia Resources
Decision Tree Application

	owner 5(b)?	purchaser 5(b)?	committed?	include in stack?	outcome #	2009 (aMW)	2010 (aMW)	2011 (aMW)	2012 (aMW)	2013 (aMW)
Wanapum										
AVWP	Yes	Yes	Yes	No	3	26.0	16.0	11.0	11.0	11.0
COPD	Yes	Yes	Yes	No	3	8.6	8.6	8.6	8.6	8.6
CWPC	Yes	Yes	No	Yes	4	0.0	0.3	0.4	0.4	0.4
EWEB	Yes	Yes	Yes	No	3	7.3	4.6	3.2	3.1	3.1
FGRV	Yes	Yes	Yes	No	3	2.2	1.6	1.3	1.3	1.3
FREC	Yes	Yes	No	Yes	4	0.0	0.3	0.4	0.4	0.4
GCPD	Yes	Yes	Yes	No	1	117.0	154.0	184.0	186.0	187.0
ICLP	Yes	Yes	No	Yes	4	0.0	0.1	0.1	0.1	0.1
KITT	Yes	Yes	Yes	No	3	0.0	0.3	0.4	0.4	0.4
KOOT	Yes	Yes	No	Yes	4	0.0	0.5	0.6	0.6	0.6
LREC	Yes	Yes	No	Yes	4	0.0	0.1	0.1	0.1	0.1
LVE	Yes	Yes	No	Yes	4	0.0	0.6	0.8	0.8	0.8
MCMN	Yes	Yes	Yes	No	3	2.2	1.6	1.3	1.3	1.3
MTFR	Yes	Yes	Yes	No	3	2.2	1.6	1.3	1.3	1.3
NLEC	Yes	Yes	No	Yes	4	0.0	0.4	0.5	0.5	0.5
PGE	Yes	Yes	Yes	No	3	60.0	37.0	26.0	25.0	25.0
PPL	Yes	Yes	Yes	No	3	60.0	37.0	26.0	25.0	25.0
PSE	Yes	Yes	Yes	No	3	34.0	22.0	15.0	15.0	14.0
RREC	Yes	Yes	No	Yes	4	0.0	0.1	0.1	0.1	0.1
SCL	Yes	Yes	Yes	No	3	0.0	12.0	14.0	14.0	14.0
SLEC	Yes	Yes	No	Yes	4	0.0	0.1	0.1	0.1	0.1
TPU	Yes	Yes	Yes	No	3	0.0	12.0	14.0	14.0	14.0
UNEC	Yes	Yes	No	Yes	4	0.0	0.2	0.2	0.2	0.2
UnknMKT	Yes	No		Yes	5	0.0	7.2	9.6	9.6	9.6
	Wanapum included in resource stack					0.0	9.9	12.9	12.9	12.9
Priest Rapids										
AVWP	Yes	Yes	Yes	No	3	12.0	14.0	13.0	13.0	13.0
COPD	Yes	Yes	Yes	No	3	5.6	8.8	9.9	9.9	9.9
CWPC	Yes	Yes	Yes	No	4	0.4	0.4	0.4	0.4	0.4
EWEB	Yes	Yes	Yes	No	3	3.4	4.0	3.7	3.6	3.6
FGRV	Yes	Yes	Yes	No	3	1.3	1.5	1.6	1.6	1.6
FREC	Yes	Yes	No	Yes	4	0.5	0.5	0.5	0.5	0.5
GCPD	Yes	Yes	Yes	No	1	229.0	202.0	213.0	215.0	216.0
ICLP	Yes	Yes	No	Yes	4	0.1	0.1	0.1	0.1	0.1
KITT	Yes	Yes	Yes	No	3	1.0	0.7	0.5	0.5	0.5
KOOT	Yes	Yes	No	Yes	4	0.7	0.7	0.7	0.7	0.7
LREC	Yes	Yes	No	Yes	4	0.1	0.1	0.1	0.1	0.1
LVE	Yes	Yes	No	Yes	4	0.9	0.9	0.9	0.9	0.9
MCMN	Yes	Yes	Yes	No	3	1.3	1.5	1.6	1.6	1.6
MTFR	Yes	Yes	Yes	No	3	1.3	1.5	1.6	1.6	1.6
NLEC	Yes	Yes	No	Yes	4	0.6	0.6	0.6	0.6	0.6
PGE	Yes	Yes	Yes	No	3	28.0	33.0	30.0	29.0	29.0
PPL	Yes	Yes	Yes	No	3	28.0	33.0	30.0	29.0	29.0
PSE	Yes	Yes	Yes	No	3	16.0	19.0	17.0	17.0	17.0
RREC	Yes	Yes	No	Yes	4	0.1	0.1	0.1	0.1	0.1
SCL	Yes	Yes	Yes	No	3	2.0	14.0	16.0	16.0	16.0
SLEC	Yes	Yes	No	Yes	4	0.1	0.1	0.1	0.1	0.1

ATTACHMENT 5
Mid-Columbia Resources
Decision Tree Application

TPU	Yes	Yes	Yes	No	3	15.0	18.0	16.0	16.0	16.0
UNEC	Yes	Yes	No	Yes	4	0.3	0.3	0.3	0.3	0.3
UnknMKT	Yes	No		Yes	5	22.0	14.0	11.0	11.0	11.0
	Priest Rapids included in resource stack					25.4	17.4	14.4	14.4	14.4
Wells										
AVWP	No	Yes	Yes	No	7	12.0	12.0	12.0	12.0	12.0
COLV	No	No		No	9	16.0	16.0	16.0	16.0	16.0
DOPD	No	No		No	6	101.0	101.0	101.0	101.0	101.0
OKPD	No	Yes	Yes	No	7	27.0	27.0	27.0	27.0	27.0
PGE	No	Yes	Yes	No	7	68.0	68.0	68.0	68.0	68.0
PPL	No	Yes	Yes	No	7	23.0	23.0	23.0	23.0	23.0
PSE	No	Yes	Yes	No	7	105.0	105.0	105.0	105.0	105.0
	Wells included in resource stack					0.0	0.0	0.0	0.0	0.0
Rocky Reach										
AVWP	No	Yes	Yes	No	7	16.0	16.0	16.0	16.0	16.0
CHPD	No	No		No	6	81.0	81.0	81.0	81.0	81.0
CLKM	No	No		No	9	123.0	123.0	123.0	123.0	123.0
DOPD	No	No		No	9	14.0	14.0	14.0	14.0	14.0
PGE	No	Yes	Yes	No	7	65.0	65.0	65.0	65.0	65.0
PPL	No	Yes	Yes	No	7	28.0	28.0	28.0	28.0	28.0
PSE	No	Yes	Yes	No	7	209.0	209.0	209.0	209.0	209.0
	Rocky Reach included in resource stack					0.0	0.0	0.0	0.0	0.0
Rock Island PH#1										
CHPD	No	No		No	6	85.0	85.0	85.0	85.0	85.0
PSE	No	Yes	Yes	No	7	85.0	85.0	85.0	85.0	85.0
	Rock Island #1 included in resource stack					0.0	0.0	0.0	0.0	0.0
Rock Island PH#2										
CHPD	No	No		No	6	61.0	61.0	61.0	61.0	61.0
PSE	No	Yes	Yes	No	7	61.0	61.0	61.0	61.0	61.0
	Rock Island #2 included in resource stack					0.0	0.0	0.0	0.0	0.0

Attachment 6 - Subpart 1, Updated Cost Projections for Boardman Coal Plant

PRC share of Boardman Coal Plant Resource - 10%

Revised Cost Projections:

FERC Form No. 1 Data - page 402 of PGE's filing, Total Plant Costs - column (b)

	FY2004	FY2004 Restated in FY2007 $$ 0.914214	FY2005	FY2005 Restated in FY2007 $$ 0.942809	FY2006	FY2006 Restated in FY2007 $$ 0.973087	3-Year Ave Costs Restated in FY2007 $$	7(b)(2) Resource Stack Values: PRC Share at 10% FY-2007 $$	7(b)(2) Resource Stack Values: PRC Share at 10% FY-1980 $$ 0.444912
Operating Cost Data:									
Coal Fuel Costs	44,256,851	48,409,728	47,834,482	50,736,132	35,492,843	36,474,481	45,206,780	4,520,678	2,011,303
Production Expenses	6,764,874	7,399,661	5,974,221	6,336,619	5,989,289	6,154,937	6,630,406	663,041	294,994
Misc. Steam power Expenses	1,192,631	1,304,542	2,169,872	2,301,497	2,066,716	2,123,876	1,909,972	190,997	84,977
Rent Expense	3,618,051	3,957,554	1,138,860	1,207,943	257,963	265,098	1,810,198	181,020	80,538
Allowances	(7,770)	(8,499)	(19,387)	(20,563)	0	0	(9,687)	(969)	(431)
Maintenance expense	23,694,817	25,918,239	19,345,303	20,518,793	18,802,559	19,322,588	21,919,873	2,191,987	975,241
Operating Expenses - less fuel costs	35,262,603	38,571,497	28,608,869	30,344,289	27,116,527	27,866,498	32,260,762	3,226,076	1,435,319
Total Production Expenses	79,519,454	86,981,225	76,443,351	81,080,421	62,609,370	64,340,979	77,467,542	7,746,754	3,446,622
Debt Service Expense - PRC share is 100% of $8,711,726 in FY2007$$								8,717,301	3,878,429
Total Revenue Requirement								16,464,056	7,325,051
Net Generation MWh	3,540,098		3,561,174		2,414,530			337,435	337,435
Installed Capacity - MW	601		601		642		642aMW	38.52	38.52 aMW
Capacity Factor	67.2414%		67.6417%		42.9332%		60%	' @ 60%	' @ 60%
Total Cap.Plant Costs	604,085,247		622,231,117		621,871,300			129,080,980	57,429,637
Cost per MWh								$48.79	$21.71

Attachment 6 - Subpart 1, Updated Cost Projections for Boardman Coal Plant

PRC share of Boardman Coal Plant Resource - 10%

Reconfigured PRC capitalization assuming 100%				
debt financing for 10% share of capital costs:			Totals	
Original Construction Cost -1980	591,000,000			100%
Capital Additions - Assumed to have occurred in FY 2005		31,051,209		100%
PRC 10% share in 1980	59,100,000			
PRC 10% share in 2005$$		3,105,121		10%
Above Capitalized costs in 1980 $$	59,100,000		57,429,637	10%
Above Capitalized costs in 2007 $$	125,787,502	3,293,478	129,080,980	10%
Interest Rate	0.05420		0.05420	
Number of years	30		30	
Mortgage based pymt for 12 months	8,494,881		8,717,301	= Debt service for FY2007 @ 5.42% in 2007$$
			3,878,429	= Debt service for FY1980 @ 5.42% in 2007$$

Assumed facts surrounding PGE's Boardman resource:

Total Capitalized Cost - 1980	591,000,000
Debt/Capital Mix	80 /20
Amount financed in 1980	472,800,000
30 year Bond @10% in 1980	10.00%
Refinanced in 1990 @ 8%	8.00%
Refinanced in 2000 @ 6%	6.00%

* Inflator conversion factor of .444912, was used to convert
the resource cost data thats expressed in 2007 dollars to 1980 dollars.

Cowlitz Falls Hydro Project Resource - Revised Cost Projections

Amounts paid/projected by BPA for the resource - revenue requirement amounts:

GDP Inflation Factors Projections		1.021	1.021	1.021	1.021	1.021	1.021	1.021	1.021
Program Case Revenue Requirement:	**FY2005**	**FY2006**	**FY2007**	**FY2008**	**FY2009**	**FY2010**	**FY2011**	**FY2012**	**FY2013**
Operation and Maintenance Charges	1,827,804	2,176,300	2,193,000	2,239,053	2,286,073	2,334,081	2,383,096	2,433,141	2,484,237
Transmission Charges	813,842	830,933	848,382	866,198	884,388	902,961	921,923	941,283	961,050
Debt Service Payments 4.20% Actual	10,805,930	11,595,930	11,619,490	11,582,810	11,571,060	11,566,310	11,562,680	11,559,430	11,546,060
Total Amounts Paid - Prog. Case Rates	13,447,576	14,603,163	14,660,872	14,688,061	14,741,522	14,803,351	14,867,699	14,933,855	14,991,347
7(b)(2) Case Revenue Requirement:									
Operation and Maintenance Charges	1,827,804	2,176,300	2,193,000	2,239,053	2,286,073	2,334,081	2,383,096	2,433,141	2,484,237
Transmission Charges	813,842	830,933	848,382	866,198	884,388	902,961	921,923	941,283	961,050
Total O&M	2,641,646	3,007,233	3,041,382	3,105,251	3,170,462	3,237,041	3,305,019	3,374,425	3,445,287
Debt Service Payments @ 4.25%	11,642,023	11,642,023	11,642,023	11,642,023	11,642,023	11,642,023	11,642,023	11,642,023	11,642,023
Total Amounts Paid - 7(b)(2) Case Rates	14,283,669	14,649,256	14,683,406	14,747,275	14,812,485	14,879,065	14,947,043	15,016,448	15,087,311
Average Annual Energy Output/@ 26.0MWh	227,760	227,760	227,760	227,760	227,760	227,760	227,760	227,760	227,760
Cost per MWh	$62.71	$64.32	$64.47	$64.75	$65.04	$65.33	$65.63	$65.93	$66.24

Calculation of 7(b)(2) Debt Service - Average annual program case debt service FY2007-2013 = 11,572,549 = Program Case Debt Service

Assuming 30 yr term financing at interest rate of 4.20% in program case, PV of the payment
Stream of 30 annual payments @ interest rate of 4.20% = Principle Amount Financed FY2007 = 195,341,712

Debt service payments assuming, principle amount of $195,341,712, 30 annual payments, @ 4.25% = 11,642,023 = 7(b)(2) Case Debt Service

7(b)(2) Case - Resource Stack Values:		FY2007-$$	FY1980-$$
	Total O&M	3,041,382	1,353,147
	Capital Investment	195,341,712	86,909,872
	Life	30 years	30 years
	Placed in service	1992	1992

* Inflator conversion factor of .444912, was used to convert the resource cost data thats expressed in 2007 dollars to 1980 dollars. 0.444912

Attachment 6 - Subpart 3, Updated Cost Projections for Idaho Falls Hydro Project

BPA's Purchase Power Contract with City of Idaho Falls
Idaho Falls Bulb Turbine Project

7(b)(2) Resource Stack Values:

Projected Annual Energy - FY2007-2013 - MWh	123,709
Average Hourly Energy - aMW	14.1
Annual Purchase Power Cost - FY 2007$$ @39.05/MWh	$4,830,841
Annual Purchase Power Cost - FY 1980$$	$2,149,299

* Inflator conversion factor of .444912, was used to convert the resource cost data thats expressed in 2007 dollars to 1980 dollars. 0.444912

Projected Contract Pricing MWH - $39.05 at contract cap rate, cost of power is expected to be at the cap during the rate test period. Only one month in FY 2007 was billed at a rate below the contract cap.

Historical Generation / Purchases from IFP

W/P Reference		Average Annual Energy - MWh	Capacity Factor @18 aMW
FY	2002	111,254	70.56%
Summary	2003	113,443	71.94%
Tab	2004	110,924	70.35%
	2005	119,433	75.74%
	2006	140,770	89.28%
	5-Year Average	119,165	75.57%
	FY2004-2006 Average	123,709	78.46%

March 2007 BPA White Book Resource Values Table 5, page 23

Date in Service	1982
Capacity Peak MW	18
Firm energy aMW	19
Total Annual Energy @ 18	157,680
Total Annual Energy @ 19	166,440

Attachment 6 - Subpart 4, Updated Cost Projections for Wauna Cogeneration Project

BPA's Purchase Power Contract with Western Generation Agency
Wauna Cogeneration Project

7(b)(2) Resource Stack Values:

Projected Annual Energy - FY2007-2013 - MWh	202,758
Average hourly energy - aMW	23.14585857
Annual Purchase Power Cost - FY 2007$$	$11,318,686
Annual Purchase Power Cost* - FY 1980$$	$5,035,819

* Inflator conversion factor of .444912, was used to convert the resource cost data that's expressed in 2007 dollars to 1980 dollars. 0.444912

Contract Pricing Schedule - W/P Reference - Page 5

	Nominal Pricing	GDP Deflator 2007$$ Conversion	2007$$ Real Pricing -[1]
FY 2007	56.16	1.00000	56.16
FY 2008	57.13	1.02103	55.95
FY 2009	58.14	1.04205	55.79
FY 2010	59.21	1.06140	55.79
FY 2011	60.33	1.08242	55.74
FY 2012	61.51	1.10513	55.66
FY 2013	62.75	1.12700	55.68
		Average	55.82370048

Historical Generation / Purchases from Wauna Project:

W/P Reference		Average Hourly Energy - MWh
4	FY 1999	25.82575
4	FY 2000	22.81016
4	FY 2001	22.29335
3	FY 2002	23.90805
3	FY 2003	22.26203
3	FY 2004	23.33532
2	FY 2005	21.58635
	Average	23.14586

Note 1 - After a resource is chosen by the rates model, its annual costs (stated in 1980 "real dollars") are inflated by the GDP inflator values contained in the model to values contained in the model to the nominal dollars for the years of the rate test period, and these costs are added to the revenue requirement of the 7(b)(2) Case for each of the years this resource is meeting the loads of the 7(b)(2) Case. Using an average of the unadjusted nominal dollars would double count the inflation adjustment.

Attachment 6 - Subpart 5, Updated Cost Projections for Nine Canyon Wind Project

Operating Budget / Funding Requirements

($ 000)

	Percent	**FY2006 Budget**	**FY2007 Budget Projection**	**FY2007 Non-Dedicated Portion**
Inflation Adjustment			1.021	0.4222
Projected Costs of Operations:				
Labor & Overheads	9.66%	667	681	288
Equipment / materials / Services	9.63%	665	679	287
Insurance	2.61%	180	184	78
Lease Payments	3.66%	253	258	109
Tx Costs	0.90%	62	63	27
Contingency / Fees	2.90%	200	204	86
Other Costs	4.17%	288	294	124
Taxes	0.51%	35	36	15
Subtotal Operating Costs	34.03%	2,350	2,399	1,013
Depreciation	52.14%	3,600	3,600	1,520
Interest Financing Costs	61.51%	4,247	4,247	1,793
Gross Generation Costs	147.68%	10,197	10,246	4,326
Renewable Energy Production Incent. Credits (REPI)	-37.90%	(2,617)	(2,617)	(1,105)
Net Generation Costs	109.78%	7,580	7,629	3,221
Net Generation Costs per above	109.78%	7,580	7,629	3,221
Less Depreciation Expense	-52.14%	(3,600)	(3,600)	(1,520)
Capital requirements	0.16%	11	11	5
Bond Retirement / Trustee Fees	47.34%	3,269	3,269	1380
Interest Income	-5.14%	(355)	(355)	(150)
Net Revenue Requirement	100.00%	6,905	6,954	2,936
Check				2,936
Total Net Generation (MWh)		175,300	175,300	74,016
Cost of Power ($/MWh)		$39.39	$39.67	$39.67
Capacity Factor			0.31415095	0.31415095

7(b)(2) Resource Stack Amounts -			
Portions Not Dedicated to Native Load:		**FY 2007$$**	**FY 1980$$**
Revenue Requirement Allocation to Non-Dedicated Portions = 42.21%		$2,936	$1,306
Share of total net generation (MWh)		74,016	74,016
Average energy per hour (aMW)		8.45	8.45
Share of name plate rating		0.00	26.90
GDP - Deflator to convert 2007$$ to 1980$$ =	0.444912		

Attachment 6 - Subpart 5, Updated Cost Projections for Nine Canyon Wind Project

Energy NW 63.7MW Nine Canyon wind power project allocations

Nine Purchasers	Phase 1 MW Share	Phase 2 MW Share	Total MW Share	% total	Resource Dedicated to native Load?
PUD No. 1 of Benton County	3.01	0	3.01	4.72%	NO
PUD No. 1 of Chelan County	6.01	1.95	7.96	12.49%	YES
PUD No. 1 of Douglas County	3.01	6.8	9.81	15.40%	Quasi[1]
PUD No. 1 of Grays Harbor	6.01	1.95	7.96	12.49%	NO
PUD No. 1 of Lewis County	1	0	1.00	1.57%	Yes
PUD No. 1 of Okanogan County	12.03	3.9	15.93	25.00%	NO
PUD No. 2 of Grant County	12.03	0	12.03	18.88%	Quasi[1]
PUD No. 3 of Mason County	1	1	2.00	3.14%	Yes
Energy Northwest CGS	2.01	0	2.01	3.15%	Yes
Cowlitz Co PUD (assigned from ENW)	2	0	2.00	3.14%	Yes
Total	48.11	15.6	63.71	100%	

Amount of preference owned resource that is NOT dedicated to serve regional preference loads. 26.9aMW 42.22%

<u>**Note 1**</u>. Resource is part of the utilities resource mix, it is not treated as a firm resource, they have not entered into specific sales contracts for the sale of specific wind energy from this resource at this time. Utility is not sure how this resource will be used during the rate test period.

Page 2 of 2

BPA Billing Credits - Summary

BPA Billing Credits - Program Case Costs - $2007$$

Summary:	Average MWh	Total MW/Year	Annual Cost	Cost Per MWh	(A) Operating Costs 25%	(B) Capital / Debt Service 75%	(C) P.V. of (B) @ 5.24% / for 25 yrs.	Debt Service (D) @ 5.42% for 25 yrs.
Project A - South Fork Tolt Hydro	5.2	45,163	$2,691,739	$59.60	$672,935	$2,018,804	27,780,916	2,054,909
Project B - Wynoochee Hydro Project	3.6	31,483	$1,722,401	$54.71	$430,600	$1,291,801	17,776,572	1,314,904
Project C - Smith Creek Hydro Project	7.0	61,179	$1,271,161	$20.78	$317,790	$953,371	13,119,411	970,421
Project D - Short Mountain Landfill	1.7	15,207	$262,310	$17.25	$65,578	$196,733	2,707,258	200,251
	17.5	153,032	$5,947,611	$38.87	$1,486,903	$4,460,708	61,384,157	4,540,485

Annual Cost per MWh **$38.80**

BPA Billing Credits - 7(b)(2) Case Costs - 2007$$

Summary:	**Average MWh**	**Total MW/Year**	**Annual Cost**	**Cost Per MWh**	**Operating Costs 25%**	**25 year Life (D) Capital / Debt Service 75%**
Project A - South Fork Tolt Hydro	5.2	45,163	$2,727,844	$60.40	$672,935	2,054,909
Project B - Wynoochee Hydro Project	3.6	31,483	$1,745,504	$55.44	$430,600	1,314,904
Project C - Smith Creek Hydro Project	7.0	61,179	$1,288,211	$21.06	$317,790	970,421
Project D - Short Mountain Landfill	1.7	15,207	$265,829	$17.48	$65,578	200,251
	17.5	153,032	$6,027,388	$39.39	$1,486,903	4,540,485

Annual Cost per MWh **$39.32**

Resource Stack information in 1980$$:

Summary:	**Average MWh**	**Total MW/Year**	**Annual Cost**	**Cost Per MWh**	**Operating Costs 25%**	
Project A - South Fork Tolt Hydro	5.2	45,163	$1,213,650	$26.87	$299,397	$914,254
Project B - Wynoochee Hydro Project	3.6	31,483	$776,596	$24.67	$191,579	$585,017
Project C - Smith Creek Hydro Project	7.0	61,179	$573,141	$9.37	$141,389	$431,752
Project D - Short Mountain Landfill	1.7	15,207	$118,270	$7.78	$29,176	$89,094
	17.5	153,032	2,681,657	$17.52	$661,541	$2,020,116

GDP - Deflator to convert 2007$$ to 1980$$ = 0.444912

Attachment 6 - Subpart 6, Updated Cost Projections for Billing Credit Resources
Billing Credit Resources - Detail
Forecasted Cost of Resource During FY2007-2009

Project A - South Fork Tolt Hydro Project

				Initial 2007-2009 Rates				Declared Project Generation								
Month	**Hours**	HLH	LLH	HLH $/MWh	LLH $/MWh	Demand $/kW	Ld Var $/MWh	HLH MWh	LLH MWh	Demand kW	Alt Cost $/MWh	PF Power Only $	PTP-06 1.487	AC$ $	PF Power plus Tx $	**Billing Credit** $
October	745	416	329	33.70	29.23	1.17	0.53	4085	0	11200	94.8	150,769	22,305	387,258	173,074	214,185
November	720	416	304	36.02	30.72	1.25	0.53	3966	0	11200	94.8	156,855	22,305	375,977	179,160	196,816
December	744	432	312	37.59	31.96	1.31	0.53	4136	0	11200	94.8	170,144	22,305	392,093	192,449	199,644
January	744	432	312	31.91	26.97	1.11	0.53	4158	0	11300	94.8	145,225	22,305	394,178	167,530	226,649
February	672	368	304	32.59	27.73	1.13	0.53	3783	0	11300	94.8	136,057	22,305	358,628	158,362	200,266
March	744	432	312	30.23	25.86	1.05	0.53	4180	0	11300	94.8	138,226	22,305	396,264	160,531	235,733
April	719	416	303	28.37	24.01	0.99	0.53	4060	0	11300	94.8	126,369	22,305	384,888	148,674	236,214
May	744	416	328	23.70	19.19	0.82	0.53	4933	0	12300	94.8	126,998	22,305	467,648	149,303	318,345
June	720	416	304	21.45	14.25	0.75	0.53	5710	0	13600	94.8	132,680	22,305	541,308	154,985	386,324
July	744	432	312	26.42	22.80	0.92	0.53	6993	0	15000	94.8	198,555	22,305	662,936	220,860	442,076
August	744	416	328	30.94	26.99	1.08	0.53	6702	0	14700	94.8	223,236	22,305	635,350	245,541	389,809
September	720	416	304	31.91	29.41	1.11	0.53	4644	0	12100	94.8	161,621	22,305	440,251	183,926	256,325
	8,760	5,008	3,752					45,163	0	112,900		1,866,735	267,660	4,281,452	1,589,712	2,691,740
						Average MWh		**5.2**					**Annual Cost per MWh**			**$59.60**

Project B - Wynochee Hydro Project

				Initial 2007-2009 Rates				Declared Project Generation									
Month	**Hours**	HLH	LLH	HLH $/MWh	LLH $/MWh	Demand $/kW	Ld Var $/MWh	HLH MWh	LLH MWh	Assured Energy Capabilities	Demand kW	Alt Cost $/MWh	**AC$** $	PTP-06 1.487	PF Power Costs Only $	**PF Power Plus Tx** $	**Billing Credit** $
October	745	416	329	33.70	29.23	1.17	0.53	2,040	1,614	3,654	4,910	90.9	332,149	9,547	121,672	131,218	200,931
November	720	416	304	36.02	30.72	1.25	0.53	2,432	1,777	4,209	5,850	90.9	382,598	9,547	149,502	159,048	223,550
December	744	432	312	37.59	31.96	1.31	0.53	3,042	2,197	5,239	7,040	90.9	476,225	9,547	193,787	203,334	272,891
January	744	432	312	31.91	26.97	1.11	0.53	2,775	2,004	4,779	6,420	90.9	434,411	9,547	149,724	159,270	275,141
February	672	368	304	32.59	27.73	1.13	0.53	2,315	1,912	4,227	6,290	90.9	384,234	9,547	135,572	145,119	239,115
March	744	432	312	30.23	25.86	1.05	0.53	1,423	1,028	2,451	3,290	90.9	222,796	9,547	73,057	82,603	140,193
April	719	416	303	28.37	24.01	0.99	0.53	1,118	815	1,933	2,680	90.9	175,710	9,547	53,941	63,487	112,222
May	744	416	328	23.70	19.19	0.82	0.53	0	0	0	0	90.9	-	9,547	-	9,547	(9,547)
June	720	416	304	21.45	14.25	0.75	0.53	0	0	0	0	90.9	-	9,547	-	9,547	(9,547)
July	744	432	312	26.42	22.80	0.92	0.53	1,045	754	1,799	2,420	90.9	163,529	9,547	47,025	56,572	106,958
August	744	416	328	30.94	26.99	1.08	0.53	912	719	1,631	2,190	90.9	148,258	9,547	49,988	59,535	88,723
September	720	416	304	31.91	29.41	1.11	0.53	902	659	1,561	2,170	90.9	141,895	9,547	50,572	60,119	81,776
	8,760	5,008	3,752					18,004	13,479	31,483	43,260		2,861,805	114,558	1,024,840	1,139,398	1,722,407
							Average MWh	**3.6**						**Annual Cost per MWh**			**$54.71**

Attachment 6 - Subpart 6, Updated Cost Projections for Billing Credit Resources
Billing Credit Resources - Detail
Forecasted Cost of Resource During FY2007-2009

Project C - Smith Creek Hydro Project

Month	Hours	HLH	LLH	Initial 2007-2009 Rates: HLH $/MWh	LLH $/MWh	Demand $/kW	Ld Var $/MWh	Declared Project Generation: HLH MWh	LLH MWh	Assd Energy Capability	Demand kW	Alt Cost $/MWh	AC$ $	PTP-06 1.487	PF Power Costs Only $	PF Power Plus Tx $	Billing Credit $
October	745	416	329	33.70	29.23	1.17	0.53	710	562	1272	1707	46.0	58,512	2,539	42,353	44,892	13,620
November	720	416	304	36.02	30.72	1.25	0.53	501	366	867	1204	46.0	39,882	1,791	30,794	32,585	7,297
December	744	432	312	37.59	31.96	1.31	0.53	206	149	355	477	46.0	16,330	710	13,131	13,841	2,489
January	744	432	312	31.91	26.97	1.11	0.53	15	11	26	35	46.0	1,196	52	815	866	330
February	672	368	304	32.59	27.73	1.13	0.53	251	208	459	683	46.0	21,114	1,016	14,721	15,737	5,377
March	744	432	312	30.23	25.86	1.05	0.53	401	290	691	929	46.0	31,786	1,381	20,598	21,979	9,807
April	719	416	303	28.37	24.01	0.99	0.53	4,708	3,429	8137	11317	46.0	374,302	16,829	227,100	243,928	130,374
May	744	416	328	23.70	19.19	0.82	0.53	14,841	11,701	26542	35675	46.0	1,220,932	53,048	605,526	658,574	562,358
June	720	416	304	21.45	14.25	0.75	0.53	11,515	8,415	19930	27681	46.0	916,780	41,161	387,672	428,833	487,947
July	744	432	312	26.42	22.80	0.92	0.53	1,662	1,200	2862	3847	46.0	131,652	5,720	74,808	80,529	51,123
August	744	416	328	30.94	26.99	1.08	0.53	0	0	0	0	46.0	-	-	-	-	-
September	720	416	304	31.91	29.41	1.11	0.53	22	16	38	53	46.0	1,748	79	1,231	1,310	438
	8,760	5,008	3,752					34,832	26,347	61,179	83,608		2,814,234	124,324	1,418,750	1,543,074	1,271,160
							Average MWh	7.0							**Annual Cost per MWh**		$20.78

Project D - Short Mountain Landfill Project

Month	Initial 2007-2009 Rates: HLH Energy	LLH Energy	Demand	Load Variance	NT-05 Network Integration	LDD	Estimated Firm Energy (MWh) 2/	Sustained Peaking Capability (MW)	Adjusted Alternative Cost 1/	AC$	HLH Energy 57% Split	LLH Energy 43% Split	Gen Demand	Load Variance	Trans Base / Load Shaping	PF$ Incls LDD	Billing Credits
October	33.70	29.23	1.17	0.53	1.487	0.045	1,173.427	3.22	51.3	$60,236	$22,540	$14,749	$3,767	$622	$4,788	$44,591	$15,645
November	36.02	30.72	1.25	0.53	1.487	0.045	1,193.917	3.22	51.3	$61,288	$24,513	$15,771	$4,025	$633	$4,788	$47,707	$13,580
December	37.59	31.96	1.31	0.53	1.487	0.045	1,399.405	3.22	51.3	$71,836	$29,984	$19,232	$4,218	$742	$4,788	$56,526	$15,310
January	31.91	26.97	1.11	0.53	1.487	0.045	1,396.713	3.22	51.3	$71,698	$25,404	$16,198	$3,574	$740	$4,788	$48,639	$23,059
February	32.59	27.73	1.13	0.53	1.487	0.045	1,362.039	3.22	51.3	$69,918	$25,302	$16,241	$3,639	$722	$4,788	$48,625	$21,293
March	30.23	25.86	1.05	0.53	1.487	0.045	1,387.746	3.22	51.3	$71,238	$23,912	$15,431	$3,381	$736	$4,788	$46,293	$24,945
April	28.37	24.01	0.99	0.53	1.487	0.045	1,262.443	3.22	51.3	$64,805	$20,415	$13,034	$3,188	$669	$4,788	$40,415	$24,390
May	23.70	19.19	0.82	0.53	1.487	0.045	1,240.418	3.22	51.3	$63,675	$16,757	$10,236	$2,640	$657	$4,788	$33,715	$29,960
June	21.45	14.25	0.75	0.53	1.487	0.045	1,205.916	3.22	51.3	$61,904	$14,744	$7,389	$2,415	$639	$4,788	$28,842	$33,061
July	26.42	22.80	0.92	0.53	1.487	0.045	1,205.512	3.22	51.3	$61,883	$18,154	$11,819	$2,962	$639	$4,788	$36,852	$25,031
August	30.94	26.99	1.08	0.53	1.487	0.045	1,301.630	3.22	51.3	$66,817	$22,955	$15,106	$3,478	$690	$4,788	$45,117	$21,700
September	31.91	29.41	1.11	0.53	1.487	0.045	1,077.722	3.22	51.3	$55,323	$19,602	$13,629	$3,574	$571	$4,788	$40,483	$14,840
TOTALS							15,206.888			$780,620	$264,283	$168,835	$40,862	$8,060	$57,458	$517,805	$262,815
					Average MWh		1.7						**Annual Cost per MWh**				$17.28

1/ Adjusted Alternative Cost is taken from total column on page 12 of Exhibit C Revision 1, average for the three years 2007-2009.
2/ These amounts are final metered energy amounts for the 2005 operating year.

Summary:	Average MWh	Total MW/Year	Annual Cost	Cost Per MWh
Project A	5.2	45,163	$2,691,739	$59.60
Project B	3.6	31,483	$1,722,401	$54.71
Project C	7.0	61,179	$1,271,161	$20.78
Project D	1.7	15,207	$262,310	$17.25
	17.5	153,032	$5,947,611	$38.87

Annual Cost per MWh [illegible]

Attachment 6 - Subpart 7, Updated Cost Projections for Conservation Resources
BPA Programmatic Conservation - Net Historical and Projected Savings and Expenditures
BPA 2007 Rate Case 7(b)(2) Resource Stack - Annual Investments and Savings

NOMINAL DOLLARS IN THE YEAR OF INVESTMENT

Appendix D, page D-22, WP-07-FS-BPA-06

	Conser. Savings aMW[2,]		Amount Revenue Expensed[2] ($ 000)	Amount Capitalized & Debt Financed[2] ($ 000)	NET Annual Expenditures [2] ($ 000)	Amortization Period[3] Years
1982	32.4		4,974	61,940	66,914	20
1983	68.6		2,907	204,092	206,999	20
1984	16.6		8,311	66,783	75,094	20
1985	17.0		24,680	103,067	127,747	20
1986	23.5		5,256	99,743	104,999	20
1987	17.2		3,928	71,631	75,559	20
1988	15.6		6,654	58,570	65,224	20
1989	20.8		12,917	46,069	58,986	20
1990	13.2		35,796	36,220	72,016	20
1991	19.0		37,557	45,714	83,271	20
1992	37.4		63,943	62,151	126,094	20
1993	59.6		55,253	96,717	151,970	20
1994	51.3		52,350	121,242	173,592	20
1995	65.9		46,657	85,252	131,909	20
1996	56.3		48,937	52,274	101,211	20
1997	54.7		25,279	32,953	58,232	20
1998	33.4		30,188	26,331	56,519	20
1999	30.3		20,657	19,728	40,385	20
2000	14.7		15,377	347	15,724	20
2001	18.5		19,905	57	19,962	20
2002	25.7		17,143	28,227	45,370	15
2003	24.7		17,286	22,900	40,186	15
2004	31.0		15,821	19,431	35,252	15
Subtotals	747.4		571,776	1,361,439	1,933,215	
2005	21.6		46,572	22,500	69,072	15
2006	26.6		48,264	44,000	92,264	15
2007	33.0		84,784	32,000	116,784	15
2008	33.0		84,195	32,000	116,195	15
2009	33.0		83,996	32,000	115,996	15
2010	33.0		83,067	40,000	123,067	15
2011	33.0		83,242	40,000	123,242	15
2012	33.0		84,387	40,000	124,387	15
2013	33.0		85,570	40,000	125,570	15
Subtotals	279.2		684,077	322,500	1,006,577	
Cumulative Savings						
1982-2013	**1,026.6**	aMW	**1,255,853**	**1,683,939**	**2,939,792**	
Cumulative Savings						
1982-2006	**795.6**	aMW	**666,612**	**1,427,939**	**2,094,551**	

Attachment 6 - Subpart 7, Updated Cost Projections for Conservation Resources
BPA Programmatic Conservation - Net Historical and Projected Savings and Expenditures
BPA 2007 Rate Case 7(b)(2) Resource Stack - Annual Investments and Savings

Notes:

1. Dollar Costs are in the Nominal Dollars Associated with the year of Expenditure/Investment. This table above replicates the table at page D-22 of Appendix D, WP-07-FS-BPA-06.
2. See the table - Net Historical Conservation Savings and Expenditures 1982-2004, With Expenditure Adjustments for Con and C&RD, Saving Adjustments for C&RD, Market Transformation and Building Codes, located at Appendix D, WP-07-FS-BPA-06 at page D-14 along with the pages that preceded that page for the basis of the adjustments to arrive at the net amount of expenditures and savings contained in the table above for the years 1982-2004. See the table - Net BPA Conservation Program Section 7(b)(2), Projected Conservation Net Expenditures - 2005-2013, located at Appendix D, WP-07-FS-BPA-06 at page D-20, along with pages D-17, D-18, and D-19 that preceded it along with the notes on page D-21 for the basis of the adjustments to arrive at the net amount of expenditures and savings for the years 2005-2013.
3. It is assumed that the financing period adopted by the Joint Operating Agency in the 7(b)(2) Case would have been consistent with the NWPPC estimates of the average composite life of conservation measures contained in their Power Plans during this period oftime.
4. All savings attributable to the adoption of building codes have been removed from the years in which the savings were estimated to have occurred. BPA's Conservation Resource Energy Data tabulation (The Red Book) no longer counts savings attributable to the adoption of BPA's Model Conservation Standards by the residential housing sector, stating that current building codes are equivalent to the MCS.

Attachment 6 - Subpart 7, Updated Cost Projections for Conservation Resources
BPA Programmatic Conservation - Net Historical and Projected Savings and Expenditures
BPA 2007 Rate Case 7(b)(2) Resource Stack
Annual Investments and Savings

INVESTMENTS IN 2007 DOLLARS

Inflation / GDP Deflator Indicies Based on Global Insight Data - 04/03/2008

Inflation Adjustment Factor To Change To $ 2007[1]		Conser. Savings aMW[2,]	Amount Revenue Expensed[2] ($ 000)	Amount Capitalized & Debt Financed[3] ($ 000)	NET Annual Expenditures [2] ($ 000)
0.519765	1982	32.4	9,570	119,169	128,739
0.543314	1983	68.6	5,351	375,643	380,994
0.564340	1984	16.6	14,727	118,338	133,065
0.582002	1985	17.0	42,405	177,091	219,496
0.596299	1986	23.5	8,814	167,270	176,084
0.611438	1987	17.2	6,424	117,152	123,576
0.631623	1988	15.6	10,535	92,729	103,264
0.655172	1989	20.8	19,715	70,316	90,031
0.680404	1990	13.2	52,610	53,233	105,843
0.703953	1991	19.0	53,352	64,939	118,291
0.722456	1992	37.4	88,508	86,027	174,535
0.739277	1993	59.6	74,739	130,827	205,566
0.755257	1994	51.3	69,314	160,531	229,845
0.771236	1995	65.9	60,496	110,539	171,036
0.785534	1996	56.3	62,298	66,546	128,844
0.798991	1997	54.7	31,639	41,243	72,882
0.809083	1998	33.4	37,311	32,544	69,856
0.820017	1999	30.3	25,191	24,058	49,249
0.836838	2000	14.7	18,375	415	18,790
0.856182	2001	18.5	23,249	67	23,315
0.872161	2002	25.7	19,656	32,364	52,020
0.890664	2003	24.7	19,408	25,711	45,119
0.914214	2004	31.0	17,306	21,254	38,560
	Subtotals	747.4	770,992	2,064,551	2,858,999
0.942809	2005	21.6	49,397	23,865	73,262
0.973087	2006	26.6	49,599	45,217	94,816
1.000000	2007	33.0	84,784	32,000	116,784
1.021026	2008	33.0	82,461	31,341	113,802
1.042052	2009	33.0	80,606	30,709	111,315
1.061396	2010	33.0	78,262	37,686	115,948
1.082422	2011	33.0	76,903	36,954	113,858
1.105130	2012	33.0	76,359	36,195	112,554
1.126997	2013	33.0	75,927	35,493	111,420
	Subtotals	279.2	654,300	309,459	963,759
		1,026.6	**1,425,292**	**2,374,010**	**3,822,758**
		795.6	**869,988**	**2,133,633**	**3,027,077**

Attachment 6 - Subpart 7, Updated Cost Projection s- Conservation Resources

BPA Conservation - Historical and Projected Savings and Expenditures

BPA 2007 Rate Case 7(b)(2) Resource Stack

Annual Investments and Savings

INVESTMENTS IN 1980 DOLLARS

Inflation / GDP Deflator Indicies Based on Global Insight Data - 04/03/2008

	Conser. Savings aMW[2,]	Amount Revenue Expensed[2] ($ 000)	Amount Capitalized & Debt Financed[2] ($ 000)	NET Annual Expenditures [2] ($ 000)
1982	32.4	4,258	53,020	57,278
1983	68.6	2,381	167,128	169,508
1984	16.6	6,552	52,650	59,202
1985	17.0	18,867	78,790	97,656
1986	23.5	3,922	74,420	78,342
1987	17.2	2,858	52,122	54,980
1988	15.6	4,687	41,256	45,943
1989	20.8	8,772	31,284	40,056
1990	13.2	23,407	23,684	47,091
1991	19.0	23,737	28,892	52,629
1992	37.4	39,378	38,275	77,653
1993	59.6	33,252	58,206	91,459
1994	51.3	30,839	71,422	102,261
1995	65.9	26,916	49,180	76,096
1996	56.3	27,717	29,607	57,324
1997	54.7	14,076	18,350	32,426
1998	33.4	16,600	14,479	31,080
1999	30.3	11,208	10,704	21,911
2000	14.7	8,175	184	8,360
2001	18.5	10,344	30	10,373
2002	25.7	8,745	14,399	23,144
2003	24.7	8,635	11,439	20,074
2004	31.0	7,699	9,456	17,156
Subtotals	747.4	343,023	928,979	1,272,002
2005	21.6	21,977	10,618	32,595
2006	26.6	22,067	20,118	42,185
2007	33.0	37,721	14,237	51,959
2008	33.0	36,688	13,944	50,632
2009	33.0	35,863	13,663	49,525
2010	33.0	34,820	16,767	51,587
2011	33.0	34,215	16,441	50,657
2012	33.0	33,973	16,104	50,077
2013	33.0	33,781	15,791	49,572
Subtotals	279.2	291,106	137,682	428,788
	1,026.6	**634,129**	**1,066,661**	**1,700,790**

* Inflator conversion factor of .444912, was used to convert the resource cost data thats expressed in 2007 dollars to 1980 dollars.

0.444912

Attachment 6 - Subpart 8

Global Insight Price Deflator and Inflation Values[1]

Year	FY GDP Price Deflator- GI Monthly (4/3/2008) 10Yr Fcst	CY GDP Price Deflator- GI Monthly (4/3/2008) 10Yr Fcst	FY2007	FY1980
1/1/60	0.21000	0.21044		
1/1/61	0.21200	0.21281		
1/1/62	0.21500	0.21572		
1/1/63	0.21700	0.21801		
1/1/64	0.22100	0.22134		
1/1/65	0.22400	0.22539		
1/1/66	0.23000	0.23180		
1/1/67	0.23700	0.23897		
1/1/68	0.24700	0.24916		
1/1/69	0.25800	0.26153		
1/1/70	0.27200	0.27538		
1/1/71	0.28600	0.28916		
1/1/72	0.29900	0.30172		
1/1/73	0.31400	0.31854		
1/1/74	0.34000	0.34721		
1/1/75	0.37200	0.38007		
1/1/76	0.39700	0.40203		
1/1/77	0.42100	0.42758		
1/1/78	0.45000	0.45763		
1/1/79	0.48600	0.49553		
1/1/80	0.52900	0.54062	0.444912	1.000000
1/1/81	0.57900	0.59128	0.486964	1.093310
1/1/82	0.61800	0.62738	0.519765	1.174296
1/1/83	0.64600	0.65214	0.543314	1.230634
1/1/84	0.67100	0.67665	0.564340	1.278170
1/1/85	0.69200	0.69724	0.582002	1.320424
1/1/86	0.70900	0.71269	0.596299	1.353874
1/1/87	0.72700	0.73204	0.611438	1.387324
1/1/88	0.75100	0.75706	0.631623	1.431338
1/1/89	0.77900	0.78569	0.655172	1.484154
1/1/90	0.80900	0.81614	0.680404	1.540492
1/1/91	0.83700	0.84457	0.703953	1.596829
1/1/92	0.85900	0.86402	0.722456	1.640842
1/1/93	0.87900	0.88391	0.739277	1.679574
1/1/94	0.89800	0.90265	0.755257	1.714785
1/1/95	0.91700	0.92115	0.771236	1.751757
1/1/96	0.93400	0.93859	0.785534	1.785207
1/1/97	0.95000	0.95415	0.798991	1.816896
1/1/98	0.96200	0.96475	0.809083	1.841544
1/1/99	0.97500	0.97868	0.820017	1.864431
1/1/00	0.99500	**1.00000**	0.836838	1.899643
1/1/01	1.01800	1.02402	0.856182	1.943658
1/1/02	1.03700	1.04193	0.872161	1.984150
1/1/03	1.05900	1.06410	0.890664	2.022883
1/1/04	1.08700	1.09462	0.914214	2.073939
1/1/05	1.12100	1.13005	0.942809	2.137319
1/1/06	1.15700	1.16568	0.973087	2.205980
1/1/07	1.18900	1.19669	1.000000	2.269360
1/1/08	1.21400	1.22027	1.021026	2.320416
1/1/09	1.23900	1.24514	1.042052	2.367952
1/1/10	1.26200	1.26820	1.061396	2.413727
1/1/11	1.28700	1.29361	1.082422	2.459501
1/1/12	1.31400	1.32051	1.105130	2.510558
1/1/13	1.34000	1.34678	1.126997	2.561615

Note 1 - Inflation /GDP Deflator indicies were obtained from Robert Mealey, Economist in BPA's finance office on 4/07/08. Mr. Mealey obtained these values from Global Insights subscribers service website.

Attachment 7

Revised Attachment A to the PFM Estimated Financing Cost Report Contained in WP-07-E-BPA-50

ATTACHMENT A

PARTICIPATION IN HYPOTHETICAL PUBLIC FINANCING ENTITY

PARTICIPANTS	AVERAGE FINANCIAL RATING[1]	% SHARE
Generators:		
Eugene Water and Electric Board	A	3.70%
Seattle	A	13.72
Tacoma	A	6.66
PUD #1 of Chelan County	AA	2.53
PUD #1 of Cowlitz County	A	6.35
PUD #1 of Douglas County	AA	.92
PUD # 2 of Grant County	AA	4.11
PUD #1 of Snohomish County	AA	9.41
PUD #1 of Clark	A	6.00
PUD #1 of Lewis County	AA	1.10
SUBTOTAL – GENERATORS (9)	A	54.50
Non-Generators:		
Springfield	A	1.24
PUD #1 of Benton County	A	2.44
Central Lincoln County PUD	A	1.67
Clatskanie PUD	A	1.21
Franklin PUD	A	1.12
PUD #1 OF Grays Harbor County	A	1.73
Umatilla Electric Cooperative Association	NA	1.14
SUBTOTAL – NONGENERATORS WITH GREATER THAN 1% SHARE (8)	A	10.55
SUBTOTAL – REMAINING NONGENERATORS (100)	NA	34.95
TOTAL (117)	A	100.00%

Note 1 – Rating represents the average of the latest reports issued by Standard and Poor's, Moody's, and Fitch rating agencies as of April 2008.